R.02-06-001

Report of Working Group 2 on Dynamic Tariff and Program Proposals

November 15, 2002

California Public Utilities Commission Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing

TABLE OF CONTENTS

LIST OF TABLES

EXECUTIVE SUMMARY

In June 2002, the Commission expressed its interest in crafting a comprehensive policy that develops demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. "Working Group 2" (WG 2) was established to address the specific issues concerning large customers (those whose average monthly demands exceed 200 kW). WG 2's mission was to develop a tariff or set of tariffs that expand demand response capabilities of large customers. In fulfilling this mission, WG 2 was further directed to pursue its best bet for a "quick win" and to develop full-scale tariffs or programs as opposed to pilots. Supplementing the mission were specific directives to WG 2 such as identifying dynamic pricing triggers, analyzing cost-effectiveness of the proposed tariffs, describing the necessary communication, metering and billing infrastructure, calculating program costs, and evaluating implementation issues.

Recommendations

A consensus of WG2 was achieved on the following points:

1. Three specific tariff design objectives should be adopted to increase customer acceptance and response to dynamic pricing tariffs: (a) simplicity, (b) stability, and (c) readily discernable customer risk (recognizing that less risk means less opportunity for bill savings by customers).

2. All dynamic pricing tariffs should be voluntary.

3. To satisfy a wide range of customer needs, and to obtain a range of experience, the Commission should adopt tariffs/program for 2003 reflecting all three types of programs proposed in this report, namely hourly pricing, critical peak pricing, and demand bidding.

4. WG2 shall continue to work toward development of a two-part RTP tariff and other forms of CPP to address key conceptual design, implementation and marketing issues that need to be resolved prior to adoption. WG2 shall submit a progress report to WG1 by April 15, 2003 as part of a commitment to have a two-part RTP tariff ready to be implemented on October 1, 2003.

5. IOU's shall be assured full cost recovery for all tariffs/programs approved in this proceeding.

6. To obtain confidence and predictability in customer demand response and to achieve consistency with the goal of program stability, the Commission should direct UDCs to each year dispatch all dynamic pricing tariffs/programs at a level necessary to assure continuing performance.

Six Proposed Options for Large Customers

WG2 presents six proposals that each proponent believes could be implemented by the summer of 2003. Each UDC advocates a single dynamic pricing offering for application to its customers in this timeframe. No party claimed to be able to implement a proposal that it did not sponsor in time for the summer of 2003. However it should be noted that one or more participants in WG 2 sponsor the following tariff and program proposals, but no consensus emerged within WG 2 that led to a recommendation to prefer one proposal over another. It is also important to note that no one proposal gained the support of every member of WG2. While in some cases non-supporting members provide brief commentary on a particular proposal that is included in this report, the absence of such commentary by a particular member does not signify that that member supports that proposal.

WG 2 represented a diversity of interests in demand response issues for large customers: investor-owned utilities, municipal utilities, large customer associations, ratepayer advocates, various demand response vendors and consultants, energy service providers, utility workers, the California Independent System Operator. Staff from the California Power Authority, the California Energy Commission and the California Public Utilities Commission served as facilitators for WG 2. While the intent of the Working Group process was to develop consensus around a set of proposals, participants in the group carried a diversity of opinion on a number of issues and there were struggles to find common ground in terms of what can be a ‘quick win’. There were differences of opinion on tariff or program designs that carry potential for gaining participation from customers, what can most effectively reduce demand, and what should be a priority given limited resources and time prior to the summer of 2003.

Table 1: Proposal Features

	SDG&E's HPO	SCE's RTP Market Index	PG&E's RTP/CPP	ACWA's CPP	Joint IOU's DBP	CPA's Demand Reserves
General Description	Energy commodity; hourly prices during on-peak hrs.	Energy commodity; formerly a temperature-based tariff; hourly prices corresponding to energy prices	Applied to 3 cent surcharge; summer period only; three price tiers	Portion of demand charges based on customer's demand during critical peak periods; energy credit for additional demand decreases	Modifies existing DBP to include a price trigger; customers bid load; payment based on forecast market hourly price	Participants reduce load for either ancillary services or call option. Includes capacity and energy payments
Eligibility	>200 kW; IDR meters/comm.	>200 kW; RTEM meters/comm.	>200 kW; on A-10, E-19, E-20; interval meters/comm.	Customers on IOU's main tariffs (eg. A-10,E-20,TOU-8)	>100 kW; interval meter; Internet	Bundled service or direct access
Source of Triggers	Avg. of day-ahead price indices	Day-ahead price from ISO or published index	Forecasted weather and load conditions for following day	IOU determines critical peak periods; min. 6 hrs. per month	ISO's day-ahead or day-of mkt. price	IOU determines call option or ancillary service
Intended Level of Participation	No limit other than elig. reqs. No estimate on response.	122 accts.; 158 MWs of max. demand (includes accts. currently on existing tariff)	1,000 MWs of load enrolled; 150 MWs of response	Customers on existing tariffs; no estimate on response.	200 accts.; 300 MWs of max. demand (SCE) 100 accts.; 82 MWs of max demand (PG&E)	Potentially 500 MWs
Costs	$100,000 for customer education and up to $2.1 million in metering costs for 200-299 kW customers w/o IDR meters that opt-in for HPO	Program costs to be determined.	Preliminary estimate: $400,000 implementation and $600,000 ongoing	Unknown	Program costs to be determined.	Unknown
Method of Cost Recovery	New balancing acct.; recovered from bundled customers	New balancing acct. & current rates; recovered from bundled customers	New & existing balancing accts.; recovered from bundled customers	Balancing acct.; recovered from ?	New or existing balancing accts. & existing rates or balancing accts.	Treat like a peaking capacity contract purchase and balancing account.
Procurement Linkage	Determine later based on performance	Expected to be factored into IRP process (long-term)	If successful, expects a linkage	Determine later based on performance	Expected to be factored into procurement	Presumed to be linked
Start Date	June 1, 2003	June 1, 2003	June 1, 2003	May 1 or June 1, 2003	June 1, 2003	Underway
Method of Implementation	Acct. executives	Customer education plan	No specifics provided	Customer service reps	Customer education plan	Existing infrastructure
Lead Time	90 days	90 days	Approx. 120 days	Anticipates several months	60-90 days	None
Other Implementation Issues	None	None	Cancel Schedule A-RTP	Participation in other D.R. programs?	None	Participation in other D.R. programs?

Experience with Existing Dynamic Tariffs/Programs

WG 2 compiled an extensive database of demand response programs and tariffs that currently exist primarily outside of California. This information supplements the level of dynamic tariffs presented at the Experiential Workshops held on September 9-10, 2002. WG 2 did not have the opportunity to discuss the material in the database in great detail. Information contained in the literature concluded that:

1. large customers, on average, reduce their demand for electricity in response to higher on-peak, hourly, or average prices, but that customer response varies significantly by business type,
2. the level of demand response or price elasticity covers a significant range, and
3. customer participation in dynamic pricing programs depends heavily on program design and the level of incentives offered

Fundamental Considerations

As part of the process in developing tariffs or programs for large customers, WG 2 wrestled with five fundamental considerations: 1. balancing an economic approach (getting the prices right) along with a reliability approach (setting targets as part of a resource planning process); 2. evaluating how revenue neutrality principles and existing rate design affect dynamic pricing; 3. voluntary versus mandatory participation; 4. the breadth and complexity of customer interest; and 5. issues pertaining to direct access customers.

WG 2 approached these topics with the intent of having participants express their knowledge, experience and positions in the interest of fleshing out the details of each topic. Fleshing out the details of these fundamental considerations would better shape and refine the program and tariff proposals.

BALANCING AN ECONOMIC APPROACH WITH A RELIABILITY APPROACH.

WG 2's effort resembled a resource planning approach as much as it did a market design approach. There has been interest both in understanding what types of demand response offerings will attract customers, as well as trying to have rates that reflect marginal costs. The group has wrestled with whether incentives might be necessary to attract customers, and whether providing incentives would still result in cost-effective demand response. These concerns highlight some of the preconditions for both economics and reliability goals, which are to design tariffs that are acceptable and attractive to customers, and present cost-reflective prices in a manner that customers understand and will respond to.

WG 2's emphasis on a reliability approach versus an economics approach stems from several factors such as the state's bout with the electricity crisis of 2000-2001, the current uncertainties and complexities surrounding the electricity market, long-term considerations such as competing supply-side resources to meet higher reserve margins, and finally a lack of data in terms of customer elasticities. Employing an economics approach with these factors in place would have been extremely difficult to achieve.

Evaluating How Revenue Neutrality and Existing Rate Design Affect Dynamic Pricing: WG 2 took into consideration revenue neutrality as part of its efforts to design tariffs and programs. System or class neutrality, defined as recovering the same amount of revenue under a new tariff as would be recovered under the old tariffs, was a design feature especially important to the investor-owned utilities.

Customer Bill Neutrality means that if a customer's usage pattern does not change, neither would its bill. While customer association representatives consider this concept to be critical in gaining customer participation in dynamic tariffs, others in WG 2 believe that such a concept would render dynamic tariffs ineffective in gaining significant demand response. Customer bill neutrality is not part of most of the tariffs proposed in this report.

A fundamental problem facing WG 2 is that existing rate designs cannot be readily modified to expose customers to market-based prices. While existing rates are at least theoretically based on marginal costs, rates for incremental consumption differ a great deal from marginal costs of supplying that consumption under the existing design of the electricity market and UDC procurement mechanisms. The problems California encountered in 2000 and 2001 leading to the imposition of surcharges to recover Department of Water Resources (DWR) revenue requirements coupled with the collapse of market prices has exacerbated the divergence between rates and marginal costs of procurement.

WG 2 could not achieve a consensus that modifying existing rates were within the scope of the proceeding. WG 2 concludes that absent a Commission effort to undertake a comprehensive rate design review, tackling these rate design issues will be impossible to resolve in any way other than ad hoc methods.

VOLUNTARY VERSUS MANDATORY

The general consensus of WG 2 is that the dynamic pricing tariffs should be voluntary. In fact, no participant appeared to favor a mandatory requirement.

While WG 2 did not endorse a mandatory requirement, it is important to note that there are benefits associated with a mandatory requirement. The main argument in favor of a mandatory requirement is that it would ensure the maximum amount of demand response, which would in turn promote optimal capacity investment decisions. Making the tariffs mandatory would also eliminate any inequities associated with self-selection. If the tariffs were voluntary, many of the volunteers would be those who would benefit from the new tariff merely by virtue of their current flat load shape, or those whose usage is flexible enough to respond easily to price signals. Peaky and inelastic consumers generally would not volunteer for the tariffs, thus a significant amount of peak demand would not be available for response.

The primary argument in favor of voluntary tariffs is the mirror image of the argument for mandatory tariffs: Peaky and inelastic customers could face significant bill increases under dynamic pricing tariffs. Some WG 2 participants also thought that there would be also due process issues if participants had no opportunity for testimony or hearings in the event that a mandatory requirement was imposed by the Commission.

CUSTOMER INTEREST ISSUES

Large customers cannot be lumped into one general category. Not only do usage patterns vary, but the percentage of overall facility budget represented by energy costs influences if, and how, customers respond to tariff changes. There is great diversity among large customers in terms of hours and timing of operation, which has a bearing on their ability to reduce load. Thus programs should be tailored to appeal to different groups of customers based on their load patterns.

Another key to designing successful dynamic pricing models is the understanding that customers will be more willing to participate if there is a true upside to the proposals. Large customers will generally avoid a tariff that is perceived to create greater price risk. This means finding programs that do not guarantee higher rates if one cannot shift load during high priced hours. Their preference would be for programs which are relatively revenue neutral on a customer basis if load is not shifted and which allow for gains in the desired time periods can be avoided or at least if reduced loads are feasible during those periods. Also, incentives have to be great enough to offset the costs that will be incurred from shedding load, i.e. those associated with delays in producing product, keeping workers on for more hours to allow for delayed completion or shifting work schedules, maintaining higher inventories, etc.

DIRECT ACCESS ISSUES

Customers who receive generation from Energy Service Providers (ESPs), often called Direct Access (DA) customers, have contracts with their ESPs that define the prices they will pay and the terms and conditions of service. WG 2 participants believe that the CPUC has no jurisdiction over ESP pricing.

Insofar as DA customers may participate in interruptible tariff programs, WG 2 believes that they should be able to participate in other such programs as long as there are no conflicts with any existing tariff provisions and their meters are compatible with the utility's meter reading system—and to the extent that their rates contain those cost elements that can be credited for performance under the program. These actions would be similar to DA customers participating in energy efficiency programs.

<u>SCE Alternative Perspective:</u>
SCE objects to the comparison that has been drawn between DA customers participating in Demand Response programs and the same set of customers participating in Energy Efficiency. It is appropriate for DA customers to participate in Energy Efficiency programs because DA customers contribute to PGC funds. It is inappropriate for DA customers to receive incentives or discounts through a utility-administered Demand Bidding programs because utilities do not procure generation for DA customers.

Screening Process

In the initial WG 2 meetings participants were asked to develop proposals that would then be compared, evaluated and refined. A screening process was conceived as a way to "filter" down to a few proposals that the WG2 could recommend as a group to WG 1. WG 2 discussed and developed a set of "screening criteria" designed to aid the group in evaluating candidate tariff designs and focusing subsequent group effort on improving a subset of the proposals into a group recommendation.

The screening criteria were grouped into six general categories:

- Policy
- Customer Choice
- Demand Reduction Potential
- Equity
- Costs
- Implementation Issues

These categories were designed to capture what the group felt were the most important issues for decision-makers to consider in implementing a tariff and to illustrate the inevitable tradeoffs required by any single tariff design.

While the purpose of the screening process had been to identify which proposals 'stood out' in terms of positives or negatives with the ultimate goal being to select only two or three proposals to go forward for detailed discussions, group discussion revolved around specific issues suggested by some of the evaluation criteria. Thus, the screening criteria process was only partially implemented and the overall benefits were marginal. In conclusion, parties chose to continue moving forward with their own proposals, albeit with some modifications suggested during group discussions.

PURPOSE OF THIS REPORT

This is the first of two reports provided by WG 2 in accordance with its mission and the directives provided to date. It is important to recognize that this report represents only half of the information needed to make an informed decision about dynamic pricing tariffs for large customers. The report due on December 13 will contain a cost-effectiveness analysis as well as marketing and education plans. These are important elements in determining which proposals are the optimal choices. This report is intended to give Working Group 1 a head start in reviewing the proposals, but a decision concerning them should wait until after the second final report has been reviewed

This report was not written by a single individual or organization but is the collective product of several participants in WG 2. Participants had an opportunity to submit alternate viewpoints concerning facts, assumptions, analyses or conclusions. These alternate viewpoints have been inserted into the body of report where they are relevant and are clearly identified. The fact that a party may not have noted a dissenting or alternate opinion should not be construed as an endorsement of facts, assumptions, analyses or conclusions contained in this report. Parties to this proceeding will also have an opportunity to file their comments on this report by December 30, 2002.

I. INTRODUCTION

On June 6, 2002, the Commission adopted R.02-06-001, its Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing." In the Administrative Law Judge's Ruling Following Prehearing Conference, dated August 1, 2002, a procedural framework was established. This framework includes three working groups: WG1 Overall Policy, WG2 Large Customer Issues, and WG3 Small Customer Issues. "Large Customers" is defined as customers with average monthly demands of 200 kW or greater.

This is the first of two final reports to be issued by WG2. It addresses proposed tariffs and programs, as well as implementation barriers for those programs. The second report will address marketing, customer education, range of impacts, cost-benefit issues, possible refinements to proposals contained in this report, and will also provide additional recommendations. The second report will be produced on December 13, 2002.

This report includes the following general sections:

- an overview of the WG2 process,
- a summary of industry experience generally with dynamic tariffs and programs for this customer group,
- a discussion of key fundamental considerations,
- a description of a process developed by WG2 to screen tariff options,
- descriptions of the specific tariff proposals,
- a discussion of generic implementation issues, and
- recommendations for WG1 and Commission action based on the findings of WG2.

The remainder of this Introduction provides a more detailed description of the mission of WG2, the nature of the WG2 process, and the role of this report.

I.A. Mission for >200 kW Customers

The mission for WG2 was defined as: "Expanding demand response capabilities by developing a tariff or set of tariffs to be used for large customers with average monthly demands of 200 kW and above."[1]
In fulfilling this mission, WG2 was further directed to pursue its best bet for a "quick win" and to develop full-scale tariffs or programs as opposed to pilots. WG 2 was also directed to use the September 9-10 experiential workshops to learn about successful implementation of dynamic tariffs in

[1] - August 1 ALJ Ruling, pg. 4

other parts of the country and to build off that experience in developing dynamic tariffs for California. In addition, WG 2 received several specific directives.[2] These directives and the actions take to address them are listed below:

Table 2: Directives give by WG 1 and Actions taken by WG 2

Directive	Action Taken
"Explore the merits of developing a tariff or set of tariffs that can take immediate advantage of the advanced meters the CEC has installed as a result of ABX1 29."	WG2 developed a screening process to assess the merits of various tariff options (Section IV). In addition, WG2 received and discussed various tariff proposals. Those proposals that remain of interest following the discussions are included in Section V.
"Recommend rate design principles and preferred tariff forms (CPP, TOU, RTP two-part, etc.) for specific rate size classes."	WG2's recommended principles are embodied in the screening process described in Section IV. Preferred tariffs will be further addressed in the second WG 2 report.
"Identify the source and process to compute and communicate wholesale market or other prices that might "drive" a dynamic tariff."	Each specific tariff proposal identifies the source and process of price signals to tariff participants. (Section V)
"Identify backup sources of prices to define dynamic tariffs if timely wholesale prices are not available or reliable."	The forthcoming CAISO Day Ahead market has been identified as a potential source for price signals. One potential backup source is day-ahead prices reflected in commercially available index publications such as Dow Jones, Platts and Bloomberg.
"Analyze the cost effectiveness of specific tariffs and identify key uncertainties in the analysis."	The second WG 2 report will include a discussion of cost-benefit analysis issues and, to the extent possible, an analysis.
"Recommend specific tariffs for the consideration of Working Group 1 and the full Commission (CPUC)."	Recommendations for specific tariffs may be provided in the second WG 2 report.
"Produce a report summarizing recommendations and a plan to implement the specific tariffs, including customer education and demand-side investment requisites."	The plan for implementing specific tariffs will be included in the second WG 2 report.

[2] - August 1 ALJ Ruling, pg. 5, September 5 ALJ Ruling, pgs. 11-13, October 2 ALJ Ruling, pgs.2-4, 12-16.

"A summary of nontariff program options designed to achieve similar demand reduction objectives."	Nontariff program options are included in this report such as a demand bidding program. (Section V)
"Metering and communication requirements to support the tariffs."	These needs are explained in each of the tariff proposals. (Section V).
"Need for additional building controls and or intelligent systems to enhance customer response."	These controls and systems are not required to implement the tariffs, so they are not addressed in the tariff proposals. To the extent the controls and systems can enhance response, they will be addressed in the marketing and customer education sections of the second WG 2 report.
"Potential need to upgrade utility billing system capabilities to support the tariffs or programs."	This information is included in each of the tariff proposals and in Section VI.
"How these options support customer preferences or customer choice."	This issue will be addressed in the marketing and customer education sections of the second WG 2 report.
"A recommendation as to whether the tariff should be voluntary or mandatory."	Section III of this report addresses the voluntary vs. mandatory issue.
"An indication of any necessary coordination with other entities, such as the CAISO."	This is included in each specific tariff proposal (Section V).
"An estimate of administrative costs."	A description of the types of administrative costs is included in each specific tariff proposals. Cost estimates will be included in the second WG2 report.
"A plan for evaluating the results of tariff deployment."	This issue will be addressed the second WG 2 report.
"An analysis of how any existing pilot efforts could be improved to provide more information for further program or tariff development."	The tariff proposals include proposals for amending existing pilot tariffs for large customers, as appropriate, with recommendations included in Section VII of this report.
"Recommended next steps for large customers, to be addressed in Phase II of this proceeding."	This issue will be addressed in the second WG 2 report.
"We encourage the Working Groups, especially WG 2, to use the two-part tariff concept as they proceed."	Section V of this report provides more details concerning this particular tariff.
Consideration of two distinct approaches: design of a model	Both approaches are covered by the proposals included in this report

dynamic pricing tariff available to IOU retail customers and design of a wholesale market bidding program available to all customers including direct access.	(Section V). The majority of the proposals address IOU retail customers, while the CPA's Demand Reserves Program is available to all customers, including direct access.

I.B. Nature of the Working Group Process

In addition to conducting the specific activities noted above, Working Group 2 was established as the forum where stakeholders could exchange information and viewpoints, deliberate on the issues, and attempt to develop consensus while pursing their preferred solutions. Working Group 2 represented a diversity of interests in demand response issues for large customers: investor-owned utilities, municipal utilities, large customer associations, ratepayer advocates, various demand response vendors and consultants, energy service providers, utility workers, and the California Independent System Operator. Staff from the California Power Authority, the California Energy Commission, and the California Public Utilities Commission served as facilitators for WG2.

Working Group 2 met nearly every week, starting on September 18, 2002 for a total of 8 meetings by the time this report was issued.[3] All meetings were open to the public and were noticed as workshops in the Commission's Daily Calendar as well as on the Commission's website. Meeting agendas were made publicly available 48 hours prior to each meeting, and minutes for each meeting were drafted and circulated to all participants. Copies of the minutes are in Appendix B.

The intent of the Working Group process was to develop the broadest support possible for specific demand response tariffs or programs for large customers. Part of the process of developing support was to first identify fundamental issues and to engage the stakeholders so that their positions could be articulated and discussed. These issues (revenue neutrality, cost recovery, direct access implications, voluntary versus mandatory issues, customer interest potential, existing market and rate design complications) are described in further detail in Section III. The meetings were facilitated[4] in a workshop format where stakeholders were encouraged to make proposals, provide their opinions, share their experience, and deliberate on issues. Participants also made

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[3] Specific dates of the Working Group 2 meetings were: September 18, 26, October 2, 11, 17, 23, November 1 and 12.

[4] Mike Jaske of the California Energy Commission served as the Working Group facilitator for each meeting. Bruce Kaneshiro of the CPUC Energy Division prepared meeting notes and David Hungerford of the CEC assembled the report.

presentations, provided handouts and materials for review, and answered questions from others.

The development of specific tariff proposals underwent a screening process, which is described in further detail in Section IV. The details of each proposal are described in Section V. Working Group 2 also received specific customer feedback and input on each proposal by distributing program details and potential rate impacts to potential customers prior to finalizing the proposals described here. In particular, several customers and customer group representatives provided feedback at WG2's meeting of November 1, 2002. The fact that a party may not have noted a dissenting or alternate opinion should not be construed as an endorsement of facts, assumptions, analysis or conclusions contained in this report.

While the intent of the Working Group process was to develop consensus around a set of proposals, participants in the group carried a diversity of opinion on a number of issues and there were struggles to find common ground in terms of what can be a 'quick win'. Some of these differences are attributable to the perspectives of the participants and the interests they represent. For example, the investor-owned utilities tended to emphasize implementation issues such as existing back office capabilities and cost recovery issues, while customer association representatives emphasized assuring enough 'gains' for customers to be interested in participating. There were differences of opinion on what has potential for gaining participation from customers, what can most effectively reduce demand, and what should be a priority given limited resources and time prior to the summer of 2003. Adding further complexity to the discussion was uncertainty about issues that extend beyond the scope of the proceeding, such as the viability of a market that could be used for price triggers and how existing rate design affects incentives to participate in dynamic pricing tariffs.

While this report provides a number of options for consideration, these options do not have consensus support from participants in Working Group 2. Each option is presented as submitted by its proponent after considering input from other working group participants. The group agreed that the appropriate forum for critical comments on the submitted proposals would be in comments on this report rather than in the text of the report itself.

Participants in Working Group 2 were able to screen out only one of the original proposals made at the outset of the process, and the proponent voluntarily removed that proposal. The choices put forward by Working Group 2 reflect what each proponent believes is the best chance for a 'quick win', and each proponent is not advocating that it can or desires to implement any other proposal but its own, with the one exception being the revised Demand Bidding Program.

All of the proposals put forward in this report are intended to put to use real-time or interval metering systems that are already in place with >200 kW customers. However, it should be noted here it is impossible to accurately know how many customers will participate, and how much they will respond. While Working Group 2 has been directed to develop full-scale tariffs rather than pilots, the assemblage of proposals contained in this report could be initially implemented as a set of pilots with a strong oversight process to gauge their success. Subsequent fine-tuning of the tariffs/programs with the most promise could occur by 2004.

I.C. Role of this Report

The mission of Working Group 2 is to develop a tariff or set of tariffs for customers with demands greater than 200 kW with the goal of expanding demand response capabilities. The role of this report is to describe those tariffs and programs in fulfillment of that mission. Several important tariff and program details are described in this report such as potential implementation barriers, methods of cost recovery, and the source of their triggering mechanisms. Beyond the fulfillment of the Working Group 2's mission, this report is also meant to inform Working Group 1 about the broad complexities and trade-offs in providing new demand response tariffs or programs to large customers.
This report was not written by a single individual or organization but is the collective product of several participants in Working Group 2 (see Appendix A for the list of authors). Drafts of each chapter in this report have been circulated among the participants of Working Group 2 prior to its publication in order to incorporate feedback and differences of opinion. In addition, participants had an opportunity to submit alternate viewpoints concerning facts, assumptions, analyses or conclusions. Alternate viewpoints have been inserted in the chapters where they are relevant and are clearly identified. Parties to the proceeding will also have an opportunity to file their comments on this report by December 30, 2002.

It is important to recognize that this report represents only half of the information needed to make an informed decision about dynamic pricing tariffs for large customers. The report due on December 13 will contain a cost-effectiveness analysis, marketing plans, education plans, and additional refinements to items contained in this report. These are important elements in determining which proposals are the optimal choices. This report is intended to give Working Group 1 a head start in reviewing the proposals, but a decision concerning them should wait until after the second WG 2 report has been reviewed.

<u>SDG&E Alternative Perspective</u>

For SDG&E, the cost to develop pilot demand response pricing programs for customers 200 kW or greater is not significantly lower than the cost to develop a voluntary, full production tariff program.

II. EXPERIENCE WITH DYNAMIC TARIFFS/PROGRAMS

In carrying out its effort to develop dynamic tariffs and programs for large customers, WG2 had access to experience with demand response pricing and programs within and outside California.

This information database includes the following sources:

(1) Filings made by the utilities, the California Energy Commission, and the California Power Authority on August 9, 2002 and ongoing workshops. These filings describe current demand response programs in California conducted by the Investor Owned Utilities and others.

(2) Presentations made in the experiential workshops held in this proceeding on September 9 and 10, 2002.

(3) The Large Customer Summary Matrix filed in this proceeding on October 1, 2002, containing summary information for large customers for programs primarily outside of California and attached as Appendix C.

This database includes information on the following topics:

(1) Customer acceptance of time-varying pricing
(2) Customer response to pricing, in the form of load shape changes
(3) Information required to design demand response programs
(4) Data regarding demand response technologies and cost of those technologies

WG2 has not discussed all of the material in the database in detail.

The discussion below is a summary of information in the database. It includes information gathered on dozens of experiments and programs conducted in California, other states, and internationally over the past quarter century. Many of these programs are time-of-use programs. There are fewer results for real-time pricing and demand bidding programs and none for critical peak pricing programs.

Following is a summary of the program results as reported in the information provided in Appendix C:

(1) Large customers, on average, reduce their demand for electricity in response to higher on-peak, hourly, or average prices.

(2) Customer response varies significantly by business type.

(3) The level of demand response, or price elasticity, has been tested and measured for a variety of customers and programs, with elasticities for individual customers ranging from 0.00 to 0.80 and peak demand reductions ranging from minimal to over 50 percent. The range of individual customer elasticities as reported based on five analyses of real-time pricing programs from 1988 to the present is shown in the table below.

Table 3: Range of Individual Customer Elasticities

Program	Customers	RTP Pricing	Elasticity Estimate	Dates
Georgia Power	1,500	Hourly	0.01 to 0.19	1990-present
Duke Power	100	Hourly	0.00 to 0.07	1997-present
Niagara Mohawk	38	Hourly	0.10 to 0.20	1988-present
Midlands (U.K.)	340	Half-hourly	0.07 to 0.35	1990-present
U.K.	520	Half-hourly	0.00 to 0.86	1990-present

(Price elasticity of demand is expressed as a ratio of the percent change in amount purchased to the percent change in price. For example, an elasticity of 0.10 means that the consumer will purchase 10 percent less electricity in response to a 100 percent higher price.)

(4) Customer participation in dynamic pricing programs depends heavily on program design and the level of the incentives offered, with participation ranging from less than 0.1 percent to over 90 percent, for one program (see Appendix C).

More detailed discussions follow.

II.A. Programs Inside California

California's three large investor-owned utilities have administered a number of different demand response programs over the last two decades, with increased attention noteworthy during approximately the last three years. This section discusses, in turn, the California utilities' experience with reliability-based programs, price-based programs, and recent experience with non-price-based programs.

II.A.1 RELIABILITY-BASED PROGRAMS

The greatest part of California's experience with demand response programs over the last two decades has been with the reliability-based, interruptible tariffs of the three large IOUs. The California Public Utilities Commission last conducted a comprehensive review of these programs in its Interruptible Load rulemaking (R.00-10-002). The discussion here is adapted from the first interim opinion issued in that rulemaking, D. 01-04-006, mimeo at pp. 2-7:

“PG&E, SCE and SDG&E have operated interruptible programs since the mid-1980’s. These programs generally operate by paying customers to reduce their electricity use during times when demand is high. Customers willing to interrupt their use, or be interrupted by the utility, are compensated for participation through fixed payments (i.e., dollars per month), a discount off their electricity rate, or on a pay-per-event basis.

“Interruptible programs are not inexpensive, however, and in some cases can cost the same or more than the prices currently charged for energy in today’s [April, 2001] dysfunctional wholesale market. For example, a customer on PG&E’s interruptible program, even if curtailed for the maximum limit of 100 hours, receives $0.84/kWh. If curtailed for only 10 hours, the price is $8.40/kWh. A customer on SCE’s system curtailed for the program limit of 150 hours would receive between $0.50/kWh and $0.80 per kWh, with higher prices for less hours of interruption. Current interruptible programs cost about $220 million per year for about 2,200 megawatts (MW) of available interruptible load.

“Traditional interruptible tariffs are targeted toward industrial and large commercial customers. Traditional programs require that the customer have a meter that records usage over time (to verify compliance), advanced telecommunications equipment (to notify of interruptions), and large loads (to be cost-effective).

“Participating customers receive a discount off of their electricity rates [those in that were in effect at the time this decision was issued] of about 15%. In exchange, they agree to interrupt service 80 to 150 hours per year (depending upon the serving utility). Customers have 30 minutes to reduce load once notified. Customers who fail to comply are subject to significant penalties, thereby providing an incentive so that a successful program permits utilities and the California Independent System Operation (ISO) to maintain system reliability and minimize rolling blackouts.

“SDG&E’s program differs slightly from that of PG&E and SCE by providing discounts for rate periods when interruptions are not called, and setting higher rates when interruptions are called. Further, SDG&E’s Schedule RTP-2 provides participants with 24-hours notice before an interruption is to take effect.”

Starting during the Summer of 2000, load curtailments began to be required under the interruptible tariff programs with a frequency that had not previously been anticipated by many participants, with a total duration of approximately 50 hours for curtailments called that summer. Approximately 40 additional hours of curtailments were subsequently required in November and December of 2000, and 100 more hours (the entire annual limit for PG&E’s program) during just the first three weeks of January, 2001. Approximately one-quarter of PG&E’s previously enrolled interruptible customer load subsequently elected to leave the program, and nearly two-thirds of SCE’s customers elected to return to firm service. The total amount of load currently available for curtailment under the state's conventional interruptible tariffs is approximately 1,000 MW.

II.A.2. PRICE-BASED PROGRAMS

II.A.2.1. Pre-Restructuring Real-Time Pricing Programs

All three of the large California utilities have offered some form of real-time pricing on an experimental basis since the mid-1980s. SDG&E's program functioned similarly to a conventional interruptible tariff (in that a limited number of very high-priced hours were signaled under conditions similar to those for an interruptible tariff, with prices that approximated the noncompliance penalties under such a tariff), while PG&E's and SCE's programs were offered as alternatives to (and to some extent competed for enrollment with) these two utilities' conventional interruptible tariffs.

PG&E's experimental real-time pricing program (designated Schedule A-RTP) was a one-part RTP tariff with a significant portion of the total rate linked to near real-time system incremental operating costs. (The system incremental costs were then scaled by common factors of between 1.5 and 2.0 to ensure revenue neutrality with respect to the standard Schedule E-19 and E-20 tariffs.) Most demand-related costs were recovered through three tiers of additional price adders that were effective during part-peak and on-peak hours every weekday (first tier), for 25 days each summer and winter (second tier, signaled on a day-ahead basis), or just 10 days each summer (third tier, signaled on a same-day basis). Thus, these demand-related RTP price adders were used in a way that was similar to what is now usually described as a "critical peak pricing" tariff.

However, PG&E's RTP program never attracted more than about 45 participants, with approximately 100 MW of total enrolled load. (Many of the best candidates for the rate were probably enrolled instead under the regular interruptible tariff.) At its peak enrollment levels, the program produced 15-20 dependable MW of estimated load reductions on the highest-priced operating days, corresponding to an average price elasticity of demand on these highest priced days of approximately 0.05 to 0.10, with an approximate tripling of the effective on-peak price producing load reductions of approximately 15 percent. As is often reported for programs of this type, the largest amounts of load reduction were associated with a relatively small number of active participants. Demand elasticity results for periods other than the small number of very high price days were generally inconclusive. The pricing algorithm for PG&E's RTP program proved difficult to adapt to the new market institutions associated with electric restructuring, and over time nearly all of the participants elected to return to service under the standard tariffs. The last PG&E RTP participant left this program in August of 2002, and PG&E requests as a clean-up matter that the

Phase 1 decision in this rulemaking authorize cancellation of the original A-RTP tariff.

SCE's RTP-2 tariff was started at approximately the same time as PG&E's A-RTP program, but used a critical peak pricing approach (with a limited number of pre-established price profiles and accompanying dispatch rules for those price profiles) that was not explicitly linked to real-time system operating costs. This approach afforded a smoother transition to post-restructuring market conditions, and SCE is now presenting a revised version of its RTP-2 tariff as its primary dynamic pricing recommendation for implementation in Phase 1 of this rulemaking.

II.A.2.2. More Recent Experiments and Experience

Beginning in the late spring of 1999, both PG&E and SCE responded to the new opportunity to reduce power purchase costs in the PX and ISO markets through new dynamic price offerings, by submitting proposals for new pilot programs that would offer market-based incentives for demonstrated real-time load reductions. The first such programs were authorized for implementation beginning in the summer of 2000. However, concerns over the exact forms of the incentives to be offered, and how load reductions would be estimated for the purpose of paying those incentives, delayed the first implementation of these new programs until the middle of that summer. To the limited extent that these programs were operated during the late summer and fall of 2000, PG&E found that the most active participants were those who were also enrolled under its conventional interruptible tariff. These customers most frequently used the program to earn incremental incentives for extended periods of load curtailments on days when they were already required to curtail load for reliability purposes. In this way, the program contributed additional hours of load curtailments on a number of days when the ISO initiated load curtailments, but did not contribute significant numbers of new or previously untapped MW of load reductions.

Additional price-based programs have been authorized for implementation in the Summers of 2001 and 2002. However, the generally low market prices that have prevailed for incremental purchases during both of these two most recent summers has made it difficult to operate these programs effectively.

II.A.3. NON-PRICE-BASED PROGRAMS

In addition to the new price-based programs that have been developed over the last three years, much effort has also been directed at development of new programs that offer non-economic incentives (e.g., reduced exposure to the risk of rotating outages).

II.B. Programs Outside California

To conveniently summarize existing information on demand response from across the country, WG2 was presented with the summary table attached as Appendix C.

While there was limited time for comprehensive review of this information by all participants, the table summarizes dozens of research papers and reports. It includes utility studies, government agency reports, and peer-reviewed academic papers. It also includes as an appendix a compendium of all of the papers and reports, which has the specific literature citations and abstracts or summaries of most of the papers and reports. Many of the papers or reports include a detailed description of the methodology of the experiment or program. The time period covered is the past 25 years. It covers scores of utility projects and programs, primarily in the U.S., but also internationally. While very extensive, the table is not comprehensive; at least as many utility programs were not included as were included. However, a significant majority of the programs and studies most relevant to this proceeding was included.

The format of the table provided as Appendix C was developed by the Energy Division of the California Public Utilities Commission, except for the bottom-most column, which was added to identify the specific source of the information included in the matrix. Data was included only for actual experience and specific results, as reported by the authors. Most of the papers and reports that are cited were contributed by qualified academic researchers, government agency researchers, and utility analytical staff. Preference was also given to published reports and reports filed with regulatory agencies.

II.B.1. SPECIFIC ISSUES IDENTIFIED REGARDING REAL-TIME PRICING PROGRAMS

The experience with real-time pricing and other economic demand response programs for large customers is somewhat limited. Real-time pricing tariffs have been in existence for 15 years, but have typically been utility pilot programs that subscribed only a handful of customers. Of more relevance to California is the experience with real-time pricing in restructured electricity markets – these tariffs and ISO or utility offered Demand Bidding programs are still relatively few and most are in their nascent stage (see Appendix C). Given these limitations, performance is difficult to judge. Low wholesale electricity prices have meant that real-time pricing customers' response thresholds may not have been met, and demand bidding programs have not been exercised nearly as often as reliability-triggered programs so our ability to gauge performance is relatively weak. Nonetheless, what information we have about real-time pricing and other economic programs outside California provides some early "lessons learned" that should be of interest to California policymakers.

The success of real-time pricing and other economic programs in stimulating price-responsive behavior and delivering load relief is still an open question. Early results indicate that, in general, load relief from such programs has been much lower and often less predictable than from reliability programs, with a few exceptions. Analysis of real-time pricing billing data indicates that real-time pricing can provide some degree of load shifting benefits, but that most of the load response is often provided by relatively few customers.

The following are factors that have been identified as critical to determining real-time pricing and other price response program success, or which explain why existing programs have not performed as well as anticipated:

(1) Low wholesale prices – some programs have not been called, others have not reached customer thresholds for response. Experience is showing that significant financial incentives are needed to stimulate sizeable customer response, even with good program design and implementation. However, there is evidence that higher prices do lead to larger amounts of response [e.g., see Chuck Goldman's "Framing Paper #1: Price-Responsive Load (PRL) Programs;" prepared for The New England Demand Response Initiative (NEDRI). March 25, 2002] – dynamic pricing programs in the Pacific Northwest during the winter and spring of 2001 were successful at eliciting market response until wholesale prices dropped, FERC rate mitigation measures were introduced, and longer-term buyback contracts were signed by utilities/customers.

(2) Diversity of program offerings –Programs can be part of a portfolio of service offerings that can be tailored to customer needs (e.g., Cinergy's PowerShare Pricing; see also: Chuck Goldman, Grayson Heffner, and Galen Barbose, "Customer Load Participation in Wholesale Markets: Summer 2001 Results, Lessons Learned and 'Best Practices;'" presented at FERC-DOE Demand Response Conference, February 2002.)

(3) Coordination of ISO and utility programs – In New York, this is reported as having been done effectively with the NYISO Emergency Demand Response Program and Day Ahead Demand Response Program.

(4) Creating synergies with existing programs – Cinergy, for example, has found a natural progression in customer marketing and acceptance from participation in "emergency" DR programs to "economic" dynamic pricing programs. Baltimore Gas & Electric has transitioned legacy interruptible programs to demand response programs.

(5) Understanding customer needs/motivations – program statistics and customer surveys provide some consistent findings:

(a) industrial customers traditionally form the backbone of most dynamic pricing programs, but participation from commercial and institutional customers is increasing

(b) a variety of customers are able to respond to prices, but certain types are more likely to than others

(c) customers join dynamic pricing programs (including real-time pricing) to save money

(d) customers are not comfortable with unmitigated price volatility

(e) customers are confused by multiple program offerings and are discouraged by complex rules/requirements and protracted financial settlement processes

(f) new marketing strategies and enabling technologies may be necessary to expand customer participation

See also: A. Faruqui, J. Hughes, and M. Mauldin, "Real Time Pricing in California: R&D Issues and Needs." Report prepared for California Energy Commission, PIER Program. October 28, 2001.

II.B.2. INFORMATION RESULTS: CUSTOMER ACCEPTANCE OF DYNAMIC PRICING TARIFFS

Large customer acceptance of dynamic pricing tariffs is found to vary widely, as illustrated by the information presented in Appendix C, with participation rates in voluntary programs ranging from below 1 percent to above 90 percent (for one program). While many large customer time-of-use programs have been mandatory, most dynamic pricing programs conducted over the past 25 years have been voluntary.

Customer satisfaction has varied widely, usually depending on whether customers perceived or actually experienced savings on voluntary dynamic tariffs.

Finally, based on limited data, customers have indicated preferences for simpler rate structures over more complex structures.

II.B.3. INFORMATION RESULTS: CUSTOMER DEMAND RESPONSE

The studies found that customers, on average, reduce electricity demand in response to higher electricity prices and in response to having more information about their energy usage. The specific level of demand response is the critical determinant of cost effectiveness of demand response programs. In contrast to programs for small commercial and residential customers, the studies found both increases and reductions in total consumption when customers switched to dynamic prices. Also, the studies found that customers reduce total electricity demand in response to higher overall electricity prices. Within these general trends, the following specific findings are also of interest:

(1) Price elasticities for individual customers ranged broadly from approximately 0.03 to 0.80, depending on a variety of factors, especially type of business.

(2) Customers reduced peak demands by a few percent to over 50 percent in some cases (under real-time pricing).

II.B.4. INFORMATION RESULTS: PROGRAM DESIGN

The studies cover a range of demand response programs and provide extensive information on program design. These studies include information on rate design, metering requirements, other technology requirements, information options, customer recruitment, and other program design elements.

II.B.4.a. Rate Design

The studies offer data on rate designs having different goals. Some rates are class revenue neutral. Others are rate schedule revenue neutral, with the dynamic pricing tariff reflecting the relative costs associated with customers participating on the tariff, based on the aggregate loads of those customers. Some rates include metering costs in customer charges or distribution rates; others have a separate meter charge. With respect to real-time pricing, the program with the highest level of participation is the two-part real-time pricing program offered by Georgia Power Company.

In creating two-part real-time pricing or other programs that require a reference load or “Customer Baseline Level (CBL),” a wide variety of issues have been discussed in different regions. Approaches used have included historical consumption, negotiated CBLs, temperature or real time adjustments, and, for demand bidding programs, five- or ten-day rolling averages of hourly consumption. Different approaches are in use today in programs such as PJM, NY ISO, NEPOOL, and ERCOT programs. (These are the regional transmission organizations in Pennsylvania-New Jersey-Maryland, New York, New England, and Texas, respectively.)

II.B.4.b. Equipment Requirements

Equipment requirements are a function of the rate design. For example, a time-of-use rate requires a time-of-use meter, while a real-time pricing rate requires an interval meter. In some cases, customers utilize customer-owned energy management systems to assist in responding to dynamic pricing. In other cases, customers take manual action during the highest cost hours. A large variety of metering and controls technology is available and has been utilized to support the implementation of demand response programs.

II.B.4.c. Available Technologies

Implementing dynamic tariffs requires two basic sets of technology. The first, metering, is required to measure the results of demand responsive actions, i.e., how many megawatts of load reduction resulted from a specific pricing or other demand response program activity? The second is the control technology used to turn off appliances or equipment in response to a dispatch signal or pricing incentive.

Advanced metering necessary to implement dynamic tariffs includes the ability for meters to record usage more frequently than monthly – typically hourly or quarter-hourly – and usually includes the ability to retrieve the data remotely via a communications network. Both telephone and wireless communications are commonly used. For time-of-use metering, manual meter reading is most common.

Large customers typically require polyphase meters, in contrast to single phase meters utilized by small commercial and residential customers. Polyphase meters are more complex and typically cost roughly an order of magnitude more than single-phase meters.

Control technologies include automatic interruption via direct load control systems and customer-controlled technologies, although customer-controlled load response is by far the most common for both reliability-based and price-based demand response programs. The technologies vary widely and can be as simple as a programmable thermostat for time-of-use rates. Control technologies also range up to highly sophisticated energy monitoring and management systems used for facility and equipment management.

III. FUNDAMENTAL CONSIDERATIONS

III.A. Economics vs. Reliability

A better title for this section would be Economics AND Reliability. The two go hand-in-hand. Working Group (WG) 2 has been keeping both concerns in mind as it develops the tariffs. An emphasis on economics manifests itself as a focus on getting the prices right, and a corresponding belief that if the prices are right, we can potentially avoid reliability problems. An emphasis on reliability is a more goal-oriented approach, with a desire to set demand reduction targets and integrate dynamic pricing into the resource planning process. The need to strike a balance between an emphasis on economics and an emphasis on reliability will become clear as soon as we begin to perform cost/benefit analyses. Even when the prices and tariffs are right, the results in terms of demand response will still be important in determining whether the tariffs are worth the costs of implementation.

In practice, WG2's approach resembles a resource planning approach as much as it does a market design approach. There has been interest both in understanding what types of demand response offerings will attract customers, as well as trying to have rates that reflect marginal costs. The group has wrestled with whether incentives might be necessary to attract customers, and whether providing incentives would still result in cost-effective demand response. These concerns highlight some of the preconditions for both economics and reliability goals, which are to design tariffs that are acceptable and attractive to customers, and present cost-reflective prices in a manner that customers understand and will respond to.

The emphasis on reliability is understandable for several reasons. First and foremost is our recent experience in the winter of 2000/2001. Second is the difficulty that an economics approach has with the specifics of the electricity market, particularly control of market power and consideration of environmental externalities. Third, in the near term, the spot market price of power may be so low that end users never take the 1-3 years that many of them need to develop the demand response capability necessary to respond to high spot prices. Thus, some price signals reflecting the longer-term reliability value help provide end users the incentives to insure they have the capability developed for the next occurrence of high spot market prices. Fourth, if we don’t develop and verify the demand response capability in California, we may end up with a greater reliance on peakers to meet higher reserves margins that the state wants to protect itself from price volatility and power shortages. And, with higher reserves from supply resources, the spot market price signals will never get high enough to elicit demand response – creating a Catch 22 situation for demand response.

Finally, we don't have enough data on customer elasticities that would allow us to merge the reliability and economics approaches into a seamless whole. Until we have that data and more experience with what we can expect from dynamic pricing, the concrete steps and goals of the reliability and resource planning approach are very reassuring. For these reasons, it is critical to put demand response tariffs into the field and to dispatch them regularly. This field experience will not only create comfort regarding expected response, but also provide valuable customer feedback to allow tariff improvements over time. With good tariff design and an idea of the response they generate, we will eventually have confidence in how dynamic pricing contributes to reliability. Dynamic pricing's contribution to reliability will be the observable behavior that is consistent and trusted enough to work its way into grid operations and resource plans.

SDG&E Alternative Perspective:

The consensus opinion of WG2 reflected in Recommendation VII.B.2 determined that "the Commission should direct UDCs to each year dispatch all dynamic pricing tariffs/programs at a level necessary to assure continuing performance." SDG&E is concerned that statements in this section go beyond the consensus in calling for dispatch on a regular basis solely for the purpo0se of data collection.

III.B. Revenue Neutrality

WG2 discussed several types of revenue neutrality: 1) System or Class Neutrality, 2) Customer Bill Neutrality, and 3) Rate or Tariff Neutrality.

System or Class Neutrality means that the same amount of revenue would be recovered under a new tariff as would be recovered under the old tariffs. This definition has been refined to mean that revenues cover costs equally under the new or old tariffs, so that any revenue decrease under a new tariff is matched by a decrease in costs of serving customers on that new tariff. System or class neutrality is a principal consideration in all the tariffs WG2 is proposing.

Customer Bill Neutrality means that if a customer's usage pattern does not change, neither would their bill. For mandatory tariffs, this could be achieved with a two-part RTP tariff, though it is also a possibility for customers whose usage pattern matches the class average of other tariff designs. Customer bill neutrality is not considered essential to the tariffs WG2 is designing, though it is thought to be a valuable feature for the marketing of two-part tariffs. Customers have indicated concerns about dynamic pricing schedules which might expose them to unexpectedly high charges.

Rate or Tariff Neutrality was first mentioned after ORA's initial presentation of revenue neutrality. Rate or Tariff Neutrality means that given a class average usage, and in the absence of demand response, a new tariff would recover the same amount of revenue as the Otherwise Applicable Tariff. Rate neutrality is valuable as a guideline for design and redesign of dynamic tariffs. It has been a featured tool for design of many of the CPP tariff proposals. The designers take the standard TOU tariff and reallocate some of the costs and recovery mechanisms from the three original tiers of the TOU tariff into the fourth, or critical peak, tier of a CPP proposal.

III.B.(1) Rate Design Issues

A fundamental problem for R.02-06-001 is that existing rate designs cannot be readily modified to expose customers to market-based prices. While existing rates are at least theoretically based on marginal costs and then scaled using equal percentage marginal cost techniques to recover necessary revenue requirements, the amount of scaling means that rates for incremental consumption differ a great deal from marginal costs of supplying that consumption under the existing design of the electricity market and UDC procurement mechanisms. The problems California encountered in 2000 and 2001 leading to the imposition of surcharges to recover Department of Water Resources (DWR) revenue requirements coupled with the collapse of market prices has exacerbated the divergence between rates and marginal costs of procurement. At least two concerns have to be resolved before marginal energy rates approximate the level of market prices.

First, there are marginal cost elements embedded in current rate designs which may be inconsistent with the current mechanisms by which UDCs obtain power supplies at the margin. For example, many tariffs for large customers have demand charges that include a generation capacity cost component. It is not at all evident that demand charges ought to include such generation capacity charges when, at the margin, UDCs obtain power through CAISO imbalance energy markets. However, since a substantial portion of UDC revenue requirements are recovered through the generation component of demand charges, one cannot lightly propose to eliminate such charges. A policy of assuring at least approximate revenue neutrality requires that some other rate element be increased to collect authorized revenues.

Second, the surcharges imposed by the Commission to pay for emergency purchases and long term DWR contracts together create a large revenue obligation. While the majority of this obligation is sunk costs, and could be recovered in large customer charges, up to now the Commission has chosen to recover them in volumetric charges. These volumetric charges have been added to the underlying base rates frozen by AB 1890, sometimes resulting in marginal energy rates that are eight to ten times larger than actual marginal energy purchase costs. Some WG2 participants believe that a portion of these charges can only be collected through energy rates, such as DWR charges as a result of legislation (AB1X).

In working to develop tariffs and programs that achieve Working Group 1's goal of demand response through dynamic price signals, some alternative perspectives were proposed. The PG&E proposal, for instance, is based on developing critical period pricing based only on the surcharge revenues, and then those rates are "layered" on top of the frozen rate components. Similarly, the SDG&E proposal is based only on the recovery of the generation-related revenues , and designs a daily rate schedule, part TOU, part RTP, to revocer the forecasted revenue requirement. These differences revelct uncertainty about the scope of rate modifications that are open ot change in this proceeding. CLECA, on the other hand, asserted that the proceeding had not properly noticed ratepayers at large that rates might change, and thus rate designs that fail to fully recover existing cost allocation from participants in new tariffs could not be shifted to other customers.

Any efforts to introduce dynamic tariffs must solve the Commission coordination issues inherent in a proceeding, such as this, charged with designing some new tariffs that impact overall revenue recovery and rates paid by all customers. Until the Commission undertakes a fundamental rate design review, tackling these rate design issues will be impossible to resolve in any way other than ad hoc methods. Despite these concerns, however, it is feasible for the Commission to authorize alternative tariffs that recover some or all of currently allocated costs, thus approximating a policy of revenue neutrality, by creating tracking accounts measuring revenue shortfalls in conjunction with an assurance of future recovery.

III.C. Voluntary vs. Mandatory

The general consensus seems to be that the dynamic pricing tariffs should be voluntary. In fact, no party appears to favor that the new tariffs be mandatory. The representatives of the customer groups expressed strongly that the dynamic pricing tariffs have to be voluntary.

The main argument in favor of mandatory tariffs is that mandatory tariffs would ensure the maximum amount of demand response. Making the tariffs mandatory would also eliminate any inequities associated with self-selection. If the tariffs were voluntary, many of the volunteers would be those who would benefit from the new tariff merely by virtue of their current flat load shape, or those whose usage is flexible enough to respond easily to price signals. Peaky and inelastic consumers generally would not volunteer for the tariffs, thus a significant amount of peak demand would not be available for response.

A secondary and more theoretical argument is that if everyone were on dynamic pricing tariffs, and those tariffs were certain to be relatively stable over time, customers would be encouraged to make investment decisions that would enable them to adapt positively to the tariffs' price signals.

A critical feature of voluntary tariffs is the implementation mechanism. Customers exhibit high levels of inertia, a phenomenon well documented by Hartman *et al*.[5] A voluntary tariff implemented on an opt-out basis will have higher participation

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[5] - "Customer Rationality and the Status Quo," Quarterly Journal of Economics, February 1991.

rates, while an opt-in tariff will likely have lower participation rates. The opt-out approach allows the maximum amount of demand response to be obtained without taking the customer's choice away of returning to the otherwise applicable tariff (time-of-use with no real-time pricing or critical peak component). Opt-out also has very low marketing costs. On the other hand, it can be

considered an unnecessary burden to force existing customers to change rate schedules when they are currently satisfied with the one they are on. Customer groups feel that making the new tariffs opt-out qualifies as a mandatory switch of tariff, despite the ability to return to the original tariff. They object to the use of "inertia" against customer interests, as an opt-out implementation would do.

As long as the non-dynamic alternative to a dynamic price tariff covers the costs of service under that tariff, the non-dynamic tariff is a valid alternative to the dynamic tariff, and neither one should be regulatorily favored over the other.

One compromise may be to offer dynamic tariffs to new customers as a default, presenting the non-dynamic tariff as an opt-out alternative, and leave existing customers on their current tariffs, making the dynamic tariff an opt-in alternative. This potential solution, however, raises two problems of its own. First, treating new customers differently than continuous customers could be considered discriminatory. Secondly, the definition of 'new' customers would need refinement for implementation of this compromise. We would need to distinguish between existing customers who are opening new accounts, and customers that are truly new to the system.

The primary argument in favor of voluntary tariffs is the mirror image of the argument for mandatory tariffs: peaky and inelastic customers could face significant bill increases under dynamic pricing tariffs. These bill increases may only be mitigable by making significant long-term investments to adapt usage patterns to the new tariff. A supplemental argument popular among those focusing on the economics perspective is that as long as each tariff recovers its costs, including, for flat rate tariffs, the cost of a hedge against price volatility, it should not make a difference to system planners what kind of tariffs customers choose to pay for their electricity usage under.

The customer groups attending WG2 are willing to consider various tariff options but they do not believe it is fair or appropriate for the Commission to make mandatory tariff changes outside of the context of a full regulatory proceeding with the opportunity for testimony and hearings. Indeed, they would consider this to be a violation of the Commission's due process responsibility. A mandatory tariff change could lead to a rate increase without an opportunity to be heard. It could also result in a tariff that is very difficult for some customers to comply with, even if a rate increase is not inevitable. These are issues to address in formal hearings during Phase 2 of a utility's General Rate Case.

SDG&E Alternative Perspective:
SDG&E is opposed to crating separate default rates for new vs. existing customers in this proceeding.

III.D. Customer Interest

LARGE CUSTOMER DIVERSITY

Customers cannot be lumped into one general category. Certainly large customers cannot. Not only do usage patterns vary, but the percentage of overall facility budget represented by energy costs influences if, and how, customers respond to tariff changes. Customers over 500 kW include such varied entities as commercial office buildings, institutions (e.g. universities, prisons), hospitals, water agencies, and manufacturers. Some operated 24 hours a day, 7 days a week, some operate in batches, with reduced load in between, or ramp up and down to meet firm backlog, while some shut down completely several weeks a year for maintenance or facility-wide vacations. Some are very temperature sensitive (e.g. universities and office buildings), and some are not (e.g. most manufacturers). Customers with 24/7 operations or batch processes will have far greater difficulty shedding load for several hours on a day's notice than will office buildings that can respond with HVAC and lighting changes. Some customers, e.g. drug manufacturers, silicon chip producers and steel makers, can lose their entire output if there are any interruptions in their processes. One consideration in the development of price-responsive tariffs is that the most electricity-intensive customers are often those whose usage is less flexible, (e.g. 24/7 or batch processed based on perishable raw material inputs like food processing), unless they have back-up generation and suitable air permits, or have machinery with large loads that can be turned off and on based on short notice.

DYNAMIC PRICING ISSUES

It seems logical to design programs that are tailored to appeal to different groups of customers based on their load patterns. For example, a day-ahead-noticed CPP that cannot exceed 3-4 hours per day could work well for commercial customers who can increase (or decrease) building temperatures, have viable day-lighting, etc. It could also work for those manufacturers who can turn off some significant equipment for several hours without ruining the rest of their processing. It will not work for hospitals or other entities that have true 24/7 requirements with little load variation.

One key to designing successful dynamic pricing models is understanding that customers will be more willing to participate if there is a true upside to the proposals. Large customers will generally avoid a tariff that is perceived to create greater price risk. This means finding programs that do not guarantee higher rates if one cannot shift load during high priced hours. Their preference would be for programs which are relatively revenue neutral on a customer basis if load is not shifted and which allow for gains in the desired time periods can be avoided or at least if reduced loads are feasible during those periods. Also, incentives have to be great enough to offset the costs that will be incurred from shedding load, i.e. those associated with delays in producing product, keeping workers on for more hours to allow for delayed completion or shifting work schedules, maintaining higher inventories, etc. As long as the participation of these customers results in lower overall system costs, it is appropriate for these customers to receive a net economic benefit for their behavior changes. If policy-makers wish to share those benefits with other customers, they must keep in mind that insufficient incentives do not occur, or their programs will be ineffective.

DA customers should not be charged for costs associated with utility critical peak generation pricing programs and tariff since utility generation costs are for electricity to be supplied to utility bundled customers.

DEMAND BIDDING ISSUES

Demand bidding can be quite attractive for customers who have the flexibility to shift their loads around, and for whom there are net economic benefits. Some of these customers are currently on interruptible rates and are not in a position to participate in both types of programs. This is because there has been an ongoing issue surrounding the fact that most demand bidding proposals send price signals to customers to shed load prior to the Stage 2 event that triggers the interruptible program. There has been a concern that customers who shed load in response to price signals, especially those involving any potential incentives, should not be permitted to “double dip” and receive interruptible incentives as well. However, interruptible customers have already demonstrated both an interest and an ability to participate in demand side programs, making them attractive candidates for an appropriately structured demand bidding program. When the interruptible rate programs end at the end of the year 2003, these customers may well have an interest in demand bidding or other demand-oriented programs or tariffs.

III.E. Direct Access Issues

Customers who receive generation from Energy Service Providers (ESPs), often called Direct Access (DA) customers, have contracts with their ESPs that define the prices they will pay and the terms and conditions of service. The CPUC has no jurisdiction over ESP pricing. It would be inappropriate and likely raise legal challenges if the CPUC were to attempt to change the pricing terms of these contracts. To the extent that dynamic pricing tariffs concentrate on the generation component of rates, Direct Access customers will not be able to participate in tariffs this Working Group recommends.

Insofar as DA customers may participate in interruptible tariff programs, they should be able to participate in other such programs, as long as there are no conflicts with any existing tariff provisions, their meters are compatible with the utility's meter reading systems, and to the extent that their rates contain those cost elements that are being credited for performance under the program. Similarly, since Direct Access customers do pay CPUC-regulated rates for demand charges and other rate components, any dynamic pricing tariffs that concentrate on those components should be open to Direct Access customers. These actions would be similar to DA customers participating in energy efficiency programs.

III.F. Longer Term Issues

TWO-PART TARIFFS

Large customers think that more work must be done before the implementation of two-part tariffs. The areas of greatest concern are 1) reaching consensus on a viable and reasonable method for setting customer baseline levels and 2) providing realistic market-based price signals when peak marginal costs actually exceed average costs and when the ISO's market prices are sufficiently robust to be useful sources of price signals.

GRID BENEFITS

Large customers would also be interested in the development of a program that provides incentives for reduced demand on transmission and distribution systems at times of overall system stress to provide relief of capacity constraints on these systems. The CEC has a PIER contract investigating the benefits of demand-side options on loading on the T&D system that might provide a basis for such a program. The CPUC has jurisdiction over distribution rates that are charged to bundled customers and direct access participants. Similar to energy efficiency programs, if customers take action that produces sustainable and predictable positive effects on constrained T&D systems, they should be eligible to receive reduced T&D charges regardless of whether they are bundled or direct access customers.

DA customer participation in proposed T&D peak constraint programs should be voluntary with an opt-in or opt-out provision. Credits for customers who reduce T&D costs would be determined by the CPUC and would be available to all electric customers.

<u>SCE Alternative Perspective:</u>

This section of the report proposes that large customers should also be eligible, or receive, "incentives for reduced demand on transmission and distribution systems" if peaks are offset. SCE is concerned that this perspective is being offered late and has not been an issue of discussion in the working group. WG2 has been focused on generation related costs, principally how to pass market prices to customers on a real time basis. The particular focus has been on ways of providing price signals that correspond to system peaks so that customers alter their behavior and will reduce load, and encourage development of off-peak load.

This section, by proposing unspecified incentives, seems to ignore WG2's focus on market prices. Discussion of incentives is premature. Customers currently pay demand charges based on non-coincident demand that reflects the costs imposed on the distribution system. A customer reducing its demand will pay reduced demand charges, thus capturing all of the benefits of the cost reductions. Any discussion of T&D incentives must first explain why the current T&D price signals are inadequate. It is critical to recognize that the mechanisms used to reduce system peak loads, such as dynamic pricing, may or may not be relevant to reducing distribution peaks.

IV. SCREENING PROCESS

In its initial organizing meeting held September 18, 2002, WG2 decided that both tariff and program proposals would be considered in satisfying ALJ Rulings. In that initial WG2 meeting it became clear that parties had various proposals for tariffs or programs that they had developed in earlier proceedings or had prepared in anticipation of these discussions. It was agreed to conduct a screening process as a way to "filter" down to a few proposals that the WG2 could recommend as a group to WG1. This section explains the process that was followed and both how that goal proved to be unsuccessful, and how reshaping and finetuning proposals sponsored by parties was accomplished.

IV.A. Rationale for Criteria

One original directive to Working Group 2 was to develop, as a group, at least one dynamic tariff to submit to the Policy Working Group.6 Through the first two group meetings, held on September 18 and 25, 2002, the group discussed and developed a set of "screening criteria" designed to aid the group in evaluating candidate tariff designs and focusing subsequent group effort on improving a subset of the proposals into a group recommendation.

The group developed an initial set of criteria at the September 18 meeting and both refined and expanded that list during subsequent meetings. A evaluation matrix was distributed to all participants to allow parties to evaluate their own proposals, as well as those submitted by others, in preparation for a winnowing discussion at the October 2 meeting.

The resulting matrix grouped the evaluation criteria into six general categories:
1. Policy
2. Customer Choice
3. Demand Reduction Potential
4. Equity
5. Costs
6. Implementation Issues

These categories were designed to capture what the group felt were the most important issues for decision-makers to consider in implementing a tariff and to illustrate the inevitable tradeoffs required by any single tariff design. Each of these categories includes numerous specific criteria appropriate to that category. For example, in keeping with the directive to WG2 to develop "quick win" proposals, the policy category includes a criteria describing roll out time for a tariff or program. Each of the criteria had scoring indicators that allowed a specific proposals to be assessed. Sometimes these were numeric and

[6] ALJ Ruling of September 5, 2002, p. 12.

sometimes they were indicative. For the roll out time criteria the scoring indicator was the earliest start date for the program or tariff.

In all there were 34 criteria within the six categories, each with their own scoring indicator. The full matrix, with all the subcategories listed with self-reported evaluation of each proposal, is included in Appendix D.

IV.B. Results of Screening Process

Parties were asked to evaluate the proposals, including their own, and submit the results prior to the October 2 meeting. Parties responded with evaluations of their own proposals, but only one party formally evaluated any proposal other than its own for this purpose. As a result, the comparative value of the evaluation exercise was limited. The purpose had been to identify which proposals 'stood out' in terms of positives or negatives with the ultimate goal being to select only two or three proposals to go forward for detailed discussions. Instead, group discussion revolved around specific issues suggested by some of the evaluation criteria. Thus, while the screening criteria process seems useful in concept, it was only partially implemented and the overall benefits were marginal.

IV.B.(1) POLICY

The discussion focused on the CEC's two-part RTP proposal as to whether the program was a reasonable starting point. The IOUs expressed concern about the process of developing Customer Baseline Loads (CBLs) for individual customers. Specifically, the IOUs anticipate CBL development as costly, administratively complex, and potentially litigious (customers complaining about the CBLs a year later when their load shape has changed for different reasons). The IOUs cited their experience with the OBMC program as an example of how difficult a CBL development can be. The CEC countered that the current proposal was strictly historic for each customer, with a data variance exclusion to protect the UDC.

Some discussion focused on the criteria called "Compatible with other demand response programs". Some participants thought that incompatibility meant that a proposal had the potential to lure away customers from existing programs. Other participants did not see that as necessarily adverse (presuming that the new tariff/program was more cost-effective).

There was no clear consensus if any of the proposals were inferior or superior for this category.

IV.B.(2) CUSTOMER CHOICE

Some discussion focused on the whether the two part RTP tariff would be difficult for customers to understand, and if some customers would need to hire professionals to effectively track information necessary for the tariff to be useful. The other proposals (with the exception of SDG&E's HPO pilot and the CEC's CPP) were all graded by their proponents as 'average' in terms of customer understanding.

Some discussion emerged regarding the likelihood of substantial customer participation, but participants appeared to have defined "substantial" in different ways, thus leading to differing opinions about the scores.

The issue of hedging surfaced and whether proposals should be scored on that criteria and whether it was an appropriate criteria to include in the Customer Choice category. Some participants felt that offering hedging opportunities with the proposals increases the chances of substantial customer participation.

There was no clear consensus if any of the proposals were inferior or superior for this category.

IV.B.(3) DEMAND REDUCTION POTENTIAL

Given the somewhat sketchy proposals amount and type of load reduction the proposals could deliver. Most of the proposal proponents provided no estimate on the amount of load reduction that their proposal could provide. The group also discussed the general categories of proposals in terms of their ability to target impacts to system needs. Generally, the more proposals make use of market prices directly and the less they are constrained by numbers of days of price patterns set in advance, the better they will target response to times when it is needed.

There was no clear consensus if any of the proposals were inferior or superior for this category.

IV.B.(4) EQUITY

An important issue to some participants was minimizing gaming opportunities. Some participants felt that gaming opportunities were insignificant for all of the proposals, and therefore not a relevant category to retain.

There was no clear consensus if any of the proposals were inferior or superior for this category.

IV.B.(5) COSTS

Some discussion focused on defining "high, medium, low" costs for the proposal proponents. In general proponents defined all costs (infrastructure, O&M, marketing/education) as incremental. It was clear that no proponent had done extensive cost analyses, so it was premature to use this category of criteria for screening.

There was no clear consensus if any of the proposals were inferior or superior for this category.

IV.B.(6) IMPLEMENTATION ISSUES

No discussion specific to any one proposal emerged for this category. There was no clear consensus if any of the proposals were inferior or superior for this category. Instead, the discussion raised various generic implementation issues that any proposal would have to face.

In conclusion, parties chose to continue moving forward with their own proposals, albeit with some modifications suggested during group discussions, but not to work together as a group to develop consensus proposals. The screening process did result in one proposal being abandoned by its proponent since the general form of their proposal was similar to ones put forward by others.

IV.C Conclusion

As a result of incomplete proposals, inadequate time to fully pursue the screening process with complete proposals, and the goal of a "quick win" in mind, parties chose to continue moving forward with their own proposals. The screening process did result in one proposal being abandoned by its proponent since the general form of their proposal was similar to ones put forward by others.

The WG2 process thus shifted from screening down from many to few proposals to an in-depth review of proposals, with the result that some modifications were suggested and accepted as a result of the group discussions. As an example, PG&E modified its "day type" TOU proposal by altering the number of days in each of the three types, and shifting the relative allocation of the May 2001 surcharges compared to the current A10 and E19 surcharges. The remaining proposals reflect the ability of the sponsoring party to balance the goal of a "quick win" that could be implemented by June 2003 with achieving program designs that incorporate both features conducive to broad customer acceptance and revenue protection for the utility.

<u>SCE Alternative Perspective:</u>

SCE respectfully submits these comments as an alternative perspective on the Screening Process, as described in Section IV. The purpose of this perspective is to relay SCE's viewpoint on the screening process, which differs somewhat from that what has been presented in this section.

Section IV describes the screening process as “unsuccessful,” and that because “only one party evaluated any proposals other than its own,” the “comparative value of the exercise was limited.” Section IV then proceeds through the various criteria set to evaluate the proposals, each time concluding that “there was no clear consensus if any of the proposals were inferior or superior for this category.” The Section concludes that the group moved forward with their separate proposals, but decided “not to work together as a group to develop consensus proposals.”

In the early stages of WG2, proposals were solicited specifically from the utilities and assessed against a number of criteria. The outcome of this process recognized that in order to achieve the Commission’s stated objective of a “quick win,” it made sense to build on the tariff and rate structures already in place, rather than developing completely new proposals. This conclusion reflected concerns that had been raised about some of the new proposals, such as Two-Part Real Time Pricing (TPRTP), the availability of resources to devote both to developing new proposals and to adapting existing programs to be more dynamic price based, and the need to develop programs that customers would accept. The group’s decision to focus on modifying existing tariffs and delaying the development of the complex TPRTP seemed to best use limited and specialized resources, meet the objective of quick wins, and still eventually produce a TPRTP that would be accepted by customers.

As written, SCE does not believe that Section IV fully reflects the efforts or results of WG2. WG2 did decide that the TPRTP would be developed as a consensus proposal – albeit at a later time due to the limitation of time and resources available to develop both “quick win” modifications of existing tariffs and the TPRTP. The screening process was only one part of the group effort, and as such, is an incomplete guide to conclusions and interactions of WG2.

V. SPECIFIC TARIFF AND PROGRAM PROPOSALS

Section V of this report contains a series of specific tariff and program proposals that are sponsored by one or more groups. A described previously, the nature of the Working Group 2 process has been that entities put forward proposals for discussion in WG2 meetings. As a result of this discussion proposals are revised and embellished, but few proposals have been withdrawn. No consensus has emerged within WG2 that leads to a recommendation to prefer one proposal over another. Thus, this WG2 report leaves to WG1 and other Commission decision-making processes which ones of these proposals will be authorized.

Section V consists of eight subsections. There are four dynamic tariff proposals featuring various elements of dynamic tariff rate design. There are two program proposals for demand bidding programs. Finally, there is a description of the status of development of two-part RTP tariffs that explains how WG2 satisfies the requirements to develop such proposals that ALJ Rulings have imposed.

The existing California Power Authority (CPA) Demand reserves Partnership program (V.F.) is included here as one of two demand bidding programs for two reasons. First, pursuant to the original DWR/CPA contract and D.02-10-062, UDC may become responsible for dispatching the program, which would then require that there be strong coordination among the family of related programs. It may also be determined that the UDCs have a role in the recruitment effort that so far has falling well short of the targets CPA and DWR aspired to achieve. Second, it may not make any sense to create program marketing and education materials, or conduct campaigns for new tariffs or programs, without addressing the CPA program as one option customers could pursue. So while the Commission is not in the same decision making role for the CPA program as they are for new tariffs or demand bidding programs, it does have a role in ensuring that coordination takes place.

V.A. SDG&E Hourly Pricing Option (HPO) Program

V.A.(1) GENERAL DESCRIPTION

SDG&E proposes to modify its existing HPO pilot program for consideration as a full program option for commercial/industrial customers 200 kW or greater who have interval data recorder (IDR) measurement facilities installed. SDG&E also proposes to expand the time periods subject to variable hourly pricing to the semi-peak hours in order to increase the total number of off-peak and semi-peak hours when hourly prices are less than the default energy commodity rates.

Default Rates

Standard "bundled" electric service for medium (20-500 kW) and large (greater than 500 kW) nonresidential customers on the SDG&E system is provided under separate rate schedules for respective non-energy (Schedule AL-TOU, A-6 or PA-TOU) and energy commodity costs (Schedule EECC).

Schedule AL-TOU provides the means to recover the class-specific revenue requirement for all non-energy costs i.e. transmission, distribution, public purpose programs, etc.

Schedule EECC is designed to recover commodity energy costs incurred from both utility retained generation and DWR contracts assigned to SDG&E. Schedule EECC specifies separate energy charges for On-Peak, Semi-Peak and Off-Peak time periods

Table 4: Schedule EECC Commodity Charges

Schedule EECC Commodity Charges (for AL-TOU Customers - Effective 10/01/02)	
	$ per kWh
On-Peak	0.10420
Semi-Peak	0.08018
Off-Peak	0.08018

The following time periods are specified for On-Peak, Semi-Peak and Off-Peak on weekdays during respective Summer (May 1 – September 30) and Winter (October 1- April 30) seasons.

Table 5: Peak Periods

	Summer	Winter
On-Peak	11 AM – 6PM	5 – 8 PM
Semi-Peak	6 AM – 11 AM	6 AM – 5 PM
	6 PM – 10 PM	8 PM – 10 PM
Off-Peak	10 PM – 6 AM	10 PM – 6 AM

Saturday, Sunday and Holidays are 100% off-peak under Schedule AL-TOU.

Pilot Program

SDG&E was authorized to conduct a pilot program to offer an experimental one part commodity rate (Schedule EECC-HPO) in lieu of default service under Schedule EECC that would adjust hourly on-peak commodity rates using day-ahead energy prices published by three separate energy information services providers.

The HPO is presented to customers as an optional rate schedule for commodity energy costs. Customers electing HPO are still served under Schedule AL –TOU for non-energy cost of service.

Schedule EECC-HPO is available beginning November 2, 2002 to no more than 35 medium and large commercial/industrial customers on a first-come, first-served basis. The pilot program is scheduled to close by October 1, 2003.

Hourly Pricing Mechanism

Schedule EECC-HPO was designed to provide a clear day-ahead price signal to create an incentive for customers to (1) avoid peak usage; and (2) shift usage to off-peak periods. It provides customers with a dynamic commodity price signal despite (1) the current lack of hourly energy cost information from the California Department of Water Resources (CDWR) and (2) a robust forward hourly energy market.

The HPO program is revenue neutral by day and customer class. The hourly prices collect the same revenue as the otherwise applicable energy commodity rate based on the next-day dynamic load profile forecast for medium and large commercial/industrial customers. When peak prices rise due to higher energy costs, off-peak prices will decline to maintain the daily revenue requirement.

Expanding the time periods subject to variable hourly prices to include semi-peak hours will increase the number of hours when hourly prices decline below Schedule EECC rates. This change will increase the incentive for participants to shift loads to early and late semi-peak hours in addition to off-peak hours in order to achieve savings under the program.

Customers will know the hourly prices the day before they are effective. Off-peak prices are the same for all hours within the same time period. On-peak and semi-peak prices will vary each hour within the time period. The On-peak, semi-peak and off-peak time periods correspond with the time periods defined in SDG&E's Schedule AL-TOU. Customers are billed based on their hourly energy usage and the corresponding hourly price in effect at the time the energy is consumed.

V.A.(2) ELIGIBILITY

Under the SDG&E HPO proposal, Schedule EECC-HPO will be modified to allow all Schedule EECC commercial/industrial customers greater than 200 kW with IDR measurement installed to participate in the program. Schedule EECC customers requesting to participate without IDR measurement capability installed will be eligible once IDR metering and communication facilities are installed and operational.

Schedule EECC-HPO provides SDG&E the discretion to deny service under the pilot program to self-generation customers and to customers having two or more meters combined for billing purposes. This discretion is required because SDG&E's existing measurement/billing systems are not capable of aggregating two or more IDR meter reads prior to the calculation of a bill. An upgrade to SDG&E's billing system to relieve this constraint is already underway. This system upgrade is scheduled for implementation in the third quarter of 2003. SDG&E will propose further revisions to the eligibility criteria when the system upgrade is installed and operational.

V.A.(3) SOURCE OF TRIGGERS

The HPO mechanism was developed to address the lack of day-ahead price information from DWR. It is designed to use the average of day-ahead Palo Verde price indices published by *Platt's*, *Dow Jones* and *Bloomberg*.

Indications are that the California Independent System Operator (CAISO) will implement a day-ahead price posting sometime in 2003. Ideally, a reasonably accurate, transparent day-ahead price index from the CAISO would be the logical choice as a trigger for calculation of hourly day-ahead prices under the HPO methodology after it becomes available. Transparency concerns have been expressed regarding the FERC's October 11 rehearing order. In that order FERC stated that it will continue the existing practice of allowing bids to be submitted above the cap with the understanding that such bids cannot set the market clearing price.

V.A.(4) INTENDED LEVEL OF PARTICIPATION

SDG&E does not believe any limit should be set on customer participation beyond the eligibility limitations already discussed if the decision is made to convert Schedule EECC-HPO from pilot to full program status for nonresidential customers 200 kW or larger.

V.A.(5) SOURCES AND LEVELS OF COSTS

Program implementation costs to convert to full production include customer education materials and software, IDR measurement technology for customers between 200 and 299 kW demand, and revenue collection system enhancements.

There are approximately 1200 customer sites between 200-299 kW without IDR meters installed. At an average cost of $1750 per meter installation, full participation by these customers would increase rates by at least $2.1 million. Incremental program costs to educate customers are estimated to be $100,000. No significant additional expenses for revenue system enhancements due to full program conversion as proposed are expected at this time.

Loss of Schedule EECC revenues resulting from measurable demand response under the HPO program would also be a source of potential costs under the program.

V.A.(6) METHODS OF COST RECOVERY

Separate balancing accounts should be established for tracking (1) incremental program costs not covered in rates and (2) lost energy commodity revenues.

One of the stated goals in R. 02-06-001 is "to outline policies to cover a broad spectrum of options to be offered to consumers in return for making their demand responsive resources available to the system." To the extent that the Commission determines that the modified HPO program supports this goal then all of the costs associated with these programs should be allocated to customers in the following manner. SDG&E recommends that:

A. All capital additions incurred for the HPO program, such as IDR meters, communication hardware and related installation cost be treated as authorized additions to SDG&E plant and associated annual depreciation expense for recovery in distribution rates for all customers.

B. On-going incremental O&M costs for billing, measurement and communication equipment, and customer education and support should be planned in either the next general rate case or cost of service filing subsequent to the Commission order to implement the expanded HPO program. If the next rate case is more than two (2) years from the date of decision in R. 02-06-001, then SDG&E should be authorized to recover these costs in the next AEAP filing.

C. As a preliminary recommendation, potential reductions in energy commodity revenues resulting from customer participation in the HPO program should be tracked in a new balancing account to be established by SDG&E per Commission order D.02-10-062 to recover costs related to

UDC procurement activities. These lost revenues would be recovered in the energy commodity rates charged to all bundled service customers.

V.A.(7) LINKAGE TO PROCUREMENT ACTIVITIES

Commission Order No. D. 02-10-062 in the Generation Procurement and Renewable Resource proceeding requires the UDCs to file long-term procurement plans on April 1, 2003. The long-term procurement plans are required to include a mix of resources including demand response to fill on-peak requirements.

D. 02-10-062 cites the efforts underway in R. 02-06-001. More specifically, the Commission states its expectation that quantitative targets for utilities to procure demand response resources be developed as part of each UDC's long-term procurement plan.

One of the goals of the HPO pilot program is to gain customer participation in order to determine if the program can produce measurable demand response to high on-peak energy prices. This data will help determine whether the program should be modified or disbanded based on the results. At this time, with no customer participation in the program, development of a quantitative target for an expanded HPO program is speculative.

V.A.(8) ESTIMATED START DATE

SDG&E believes it could convert its HPO pilot to full production for a June 1, 2003 implementation date if the modified Schedule EECC-HPO was approved by March 1, 2003 for customers with IDR metering facilities already installed.

Customers requesting the HPO rate without IDR metering installed will migrate to Schedule EECC-HPO beginning with the nearest bill cycle month after the IDR meter and communications is installed.

V.A.(9) PROPOSED METHOD OF IMPLEMENTATION

SDG&E would implement the full production program through its account executives using the customer education tools developed for the pilot program.

V.A.(10) LEAD TIME FROM APPROVAL

SDG&E believes it could convert its HPO pilot to full status within 90 days of the date that tariff modifications are approved.

V.A.(11) OTHER IMPLEMENTATION ISSUES

None at this time.

V.B. SCE Real-Time Pricing-Market Index Proposal

V.B. (1) GENERAL DESCRIPTION

RTP-Market Index (RTP-MI) offers customers energy prices that reflect the hourly costs of generation service. The SCE RTP-Market Index tariff represents a change from the temperature based RTP-2 tariff presently offered by SCE. The hourly prices are contained in nine unique schedules that are designed to correspond with the energy prices that SCE expects to incur for a 24-hour period. The price schedule that applies for the day is triggered either by the ISO day-ahead energy price or a financial index to be determined, such as Bloomberg's or Platt's SP-15 indices. SCE will continue to evaluate indexes which may be used to trigger the price schedules.

Charges of RTP-Market Index are separated into three categories:

- A Monthly Customer Charge
- Hourly rates per kWh consumed that vary by season, day of the week, time of day and the day-ahead trigger price, and
- A monthly Facilities Related Demand charge that applies to the highest demand (measured in kilowatts or kW) during the month or 50% of the highest demand in the preceding 11 months, whichever, is greater.

All charges are adjusted for service voltage level.

Real-time pricing schedules are designed to correspond with the expected hourly energy costs incurred by SCE. Hourly rates per kWh are contained in nine unique schedules of hourly prices. The day of the week, season, and the trigger price for the next day determine the price schedule that will apply for the next day. Five hourly price schedules apply to summer weekdays, two schedules apply to winter weekdays and two schedules apply to weekends. All holidays are considered as weekend days. Hourly rates are generally highest on weekdays.

The RTP-Market Index hourly price schedules are attached.

Schedule RTP-Market Index
REAL TIME PRICING
Total Hourly Rate

TYPE OF DAY AND DAY-AHEAD PRICE TRIGGER[1/]

HOUR	Summer Weekday ($99/MWh) (f=1%)	Summer Weekday ($95/MWh) (f=1%)	Summer Weekday ($71/MWh) (f=3%)	Summer Weekday ($48/MWh) (f=7%)	Summer Weekday ($37/MWh) (f=13%)	Winter Weekday ($31/MWh) (f=1%)	Winter Weekday ($30/MWh) (f=45%)	Weekend ($22/MWh) (f=10%)	Weekend ($20/MWh) (f=19%)
1 a.m.	0.06854	0.06971	0.06543	0.06157	0.06927	0.05755	0.06301	0.06144	0.06324
2 a.m.	0.06864	0.06533	0.06390	0.05883	0.06509	0.05478	0.06053	0.05940	0.05899
3 a.m.	0.06913	0.06799	0.06131	0.05671	0.06913	0.05377	0.05932	0.05825	0.05635
4 a.m.	0.06956	0.06057	0.06237	0.05586	0.06096	0.05484	0.05988	0.05721	0.05641
5 a.m.	0.07122	0.06747	0.06741	0.06276	0.06739	0.06018	0.06194	0.05703	0.05599
6 a.m.	0.07243	0.07629	0.07018	0.06661	0.07002	0.06279	0.06551	0.05797	0.05797
7 a.m.	0.07603	0.07774	0.07555	0.07182	0.07764	0.07192	0.07073	0.06121	0.06040
8 a.m.	0.12384	0.08495	0.08160	0.07754	0.07790	0.07712	0.07532	0.06593	0.06452
9 a.m.	0.11451	0.10449	0.10527	0.07639	0.09293	0.07529	0.08375	0.06924	0.06530
10 a.m.	0.21211	0.13506	0.16371	0.08662	0.10134	0.07688	0.08552	0.07371	0.06805
11 a.m.	0.62056	0.63867	0.29819	0.12544	0.10065	0.08057	0.08466	0.07649	0.07011
12 noon	1.09765	0.53933	0.42598	0.11891	0.12633	0.08833	0.08740	0.07730	0.07054
1 p.m.	2.37271	0.78474	0.73003	0.23548	0.15573	0.10498	0.08709	0.08044	0.06982
2 p.m.	2.56276	0.95981	0.87721	0.24232	0.22411	0.13168	0.09202	0.08132	0.06789
3 p.m.	3.01091	1.40894	1.09268	0.29250	0.35941	0.12907	0.09275	0.08173	0.06739
4 p.m.	2.94026	0.83922	1.15867	0.23097	0.19957	0.10987	0.08967	0.08315	0.06736
5 p.m.	2.09005	0.40894	0.51768	0.16076	0.17996	0.09330	0.08411	0.08153	0.06841
6 p.m.	1.48008	0.34588	0.20514	0.10949	0.14201	0.08977	0.08561	0.07892	0.07031
7 p.m.	1.11528	0.19055	0.16171	0.07900	0.11145	0.07244	0.08526	0.07878	0.07159
8 p.m.	0.33901	0.11099	0.27017	0.08382	0.09877	0.07443	0.08411	0.07825	0.07191
9 p.m.	0.16021	0.10457	0.08343	0.07670	0.09131	0.07501	0.08294	0.07720	0.07221
10 p.m.	0.07881	0.07954	0.07593	0.07532	0.08205	0.07417	0.07516	0.07476	0.07130
11 p.m.	0.07803	0.07597	0.07266	0.06805	0.07730	0.06485	0.07102	0.07011	0.06619
12 midnt.	0.07597	0.07783	0.07230	0.06639	0.07352	0.06423	0.06757	0.06665	0.06139

1/ Price trigger is set such that it is expected to occur with the indicated frequency.

While the price schedule above, which is based on SCE's existing RTP-2 schedule, includes distribution charges, SCE currently plans a proposed Market Index tariff that will reflect distribution charges as a demand charge component rather than including such costs in the hourly RTP price schedules.

The summer season begins the first Sunday in June and continues until the first Sunday in October of each year. The winter season is the rest of the year.

Hourly prices for the next day are posted on SCE Energy Manager website by 5:00 pm daily. Customers must have Internet access to view the prices. All customers are provided Energy Manager Basic at no charge. This allows customers to view 15-minute interval energy usage for the previous day. Customers may also view their 13-month usage history and view the data in charts, graphs and tables, and download the data to their PCs.

Metering and communications equipment are provided at no charge to the customer.

RTP-Market Index participants may also enroll in SCE's interruptible programs such as BIP and ACCP but may not participate in SCE's Demand Bidding Program.

V.B. (2) ELIGIBILITY

RTP-Market Index is available to SCE bundled service commercial and industrial customers with maximum demands greater than 200 kW with appropriate metering and communications equipment. Existing RTP-2 customers will be migrated to the new RTP-Market Index tariff. Metering and communications requirements are satisfied by RTEM.

V.B. (3) SOURCE OF PRICE/DEMAND RESPONSE SIGNAL

SCE's hourly energy price schedules are triggered by a day-ahead electricity price (based on ISO or other published index, such as Bloomberg's or Platt's SP-15 indices). The prices will be set such that the schedules will be triggered at approximately the same frequency as triggered historically with SCE's RTP-2 tariff based on temperature. The day-ahead schedule of hourly prices will be available by 5 pm on the previous day. The market trigger for a given day is the highest hourly price in the schedule.

V.B. (4) INTENDED LEVEL OF PARTICIPATION

While the type of customers that participate in the current RTP-2 tariff span a wide range of SIC codes, participation is concentrated in certain identifiable industries. In order to estimate participation levels in a market-based RTP, SCE identified all customers with demand greater than 200 kW which match the existing RTP-2 load profiles by SIC code and quantified their annual maximum demands. The results of this analysis are presented in Table 1. For estimated participation levels, SCE assumed an 11% penetration rate for potential participants, based on current participation rates for RTP-2. This results in an additional 26 participants and with an aggregate maximum demand of 23 MWs.

Table 6: Target Participants in SCE RTP-MI

Industry (by SIC Code)	Current Participation		Potential New Participants*		Total RTP-MI Participation	
	No.	Max Demand (kW)	No.	Max Demand (kW)	No.	Max Demand (kW)
Constr. Sand & Gravel	17	18.8	5	2.6	22	21.4
Asphalt	9	3.7	1	0.6	10	4.3
Foundries/Fabrication	10	22.8	2	2.4	12	25.2
Air Courier Services	4	5.6	1	0.2	5	5.8
Crude Petro Pipelines	4	14.8	1	1.1	5	15.9
Industrial Gases	4	18.2	1	7.3	5	25.5
Cargo Handling	3	2.2	2	1.3	5	3.5
Ready-Mix Concrete	3	1.4	2	1.0	5	2.4
Refrig. Warehouse	3	5.1	6	4.2	9	9.3
Batteries Manf.	2	1.0	1	0.2	3	1.2
Prod. Of Purch. Glass	2	1.0	1	1.0	3	2.0
Brick & Stone	1	2.6	1	0.1	2	2.7
Industrial Chemicals	1	0.4	1	0.4	2	0.8
Linen Supply	1	0.6	1	0.2	2	0.8
Misc.	32	37.3	0	0.0	32	37.3
Total	96	135.5	26	22.6	122	158.1

* Assumes 11% penetration level for potential participants.

V.B. (5) SOURCES/LEVELS OF COSTS

In order to implement the RTP-MI tariff, SCE expects to incur incremental costs related to the following start-up activities:

- Modification of current process that accesses the day-ahead trigger (presently temperature) to re-direct that process to web sites that provide the appropriate trigger, be it an ISO day-ahead price trigger or financial index trigger
- Improvements to the current billing system to streamline the billing calculations
- Design and development of rate analysis tool to assess benefits for potential participants

- Printing and mailing information material reflecting the new program features for customer education and recruiting
- Conduct of participant focus group to assess perceptions of program features and operational issues.

Final cost estimates will be provided for the December 13, 2002 report, which will address marketing and customer education considerations as well.

V.B. (6) Method of Cost Recovery

Cost by source as well as expected cost recovery method for SCE's RTP-Market Index are provided in the Table 2 below.

Operations and Maintenance Expenses (O&M)

SCE proposes to track and record for further disposition incremental O&M through a new balancing account to be established by an interim and/or final decision in this proceeding. In addition, some costs may already be recovered in current rates. An example of that is customer recruiting, which includes primarily the time of SCE account representatives who contact potential program participants and whose labor costs are already recovered in existing rates. Costs that are recovered in current rates are not quantified for purposes of program implementation. However, since the RTP-Market Index is only a modification of the existing RTP-2 tariff, some cost categories may have no incremental costs.

Revenue Shortfall

RTP-2, the current tariff that is the model for SCE's proposed RTP-Market Index tariff, is designed to be revenue neutral with respect to TOU-8, assuming forecasted billing determinants. SCE's proposed tariff is being extended to all customers 200kW and above, a larger customer base than just TOU-8, so a "revenue shortfall" could result. Under the current regulatory framework, SCE does not anticipate that there will be any significant difficulties. SCE's distribution revenues are covered under an Electric Revenue Adjustment Mechanism (ERAM) type mechanism, the Electric Distribution Revenue Adjustment Balancing Account (EDRABA), so any shortfall in distribution revenues that does result will be recovered through the distribution balancing accounts. Generation revenues are also booked to an ERAM like mechanism under D.02-04-016 and D.02-10-062, the Electric Revenue Recovery Account (ERRA), and any shortfall resulting from a reduction in collection of generation related revenues from customers taking SCE's proposed RTP tariff would be reflected in those generation related balancing accounts. These two accounts insure cost recovery for distribution and generation related costs in SCE's post Settlement period.

Under SCE's current Settlement ratemaking methodology, reductions in revenues will also show up as reductions in Surplus and consequently reduced contributions to the recovery of PROACT. Thus, there is the possibility large revenue shortfalls resulting in reduced contributions to Surplus, would lead to the Settlement period being extended to the detriment of other customers. Consequently, this raises equity issues. In the event that these programs are implemented prior to the end of the Settlement, and the revenue shortfalls are large, SCE would propose the following:

- book the lost net revenues to its PROACT account
- book the corresponding amounts of lost net revenue to a balancing account for later recovery.

This proposal is similar to how the Commission has treated lost baseline revenues and increased CARE costs for SCE's Settlement ratemaking. SCE does not anticipate it will be necessary to implement these procedures since these programs will not be implemented until the summer.

Capital Costs

Minimal capital costs are expected to be incurred. SCE proposes to record any revenue requirements related to capitalized costs in a balancing account to be established as a result of this proceeding.

Table 7: Sources of Costs and Methods of Cost Recovery
RTP-Market Index

Cost Source	Balancing Account	Current Rates
O&M		
Billing (on-going)		X
Billing System Modifications (one-time charge)	X	
Customer Notification (one time charge)	X	
Customer Education (one-time & on-going)		
Printing & Mailing	X	
Materials Development, Communications, web site updates		X
Program Management/Admin	X	X
Customer Recruitment		X
Program Evaluation	X	X
Revenue Shortfall	X	

Capital Cost (Rate Based)	X	

V.B. (7) LINKAGE TO PROCUREMENT ACTIVITIES

In the short term, demand response programs lead to changes in energy purchases at the margin. In the long-term, these programs are expected to be factored into the integrated resource planning process, which will set the performance levels, demand response requirements and the appropriate incentive levels.

V.B. (8) ESTIMATED START DATE

SCE expects to have fully operational RTP-MI not later than June 1, 2003.

V.B. (9) PROPOSED METHOD OF IMPLEMENTATION

The key tasks to implement the RTP-Market Index and the associated time line are presented in Table 3. Key tasks to accomplish prior to roll-out are as follows:

- Customer education, which primarily involves the development of and distribution of new communications material, updating of websites and presentations/training to account representatives and existing and potential new RTP participants
- Modification of the process to acquire the trigger data
- Enhancement of the billing process
- Development of new customer tracking and reporting documents and training administrative staff in the new tariff operations
- Design and development of a rate analysis tool, and
- Participant recruitment

After the summer season, SCE proposes to evaluate the performance of participants in the program and to conduct a focus group to assess participant perceptions of the tariff features and operations.

Please see the “SCE Real Time Pricing – Market Index Program Proposed Implementation Plan” at the end of this section.

V.B. (10) LEAD TIME FROM APPROVAL

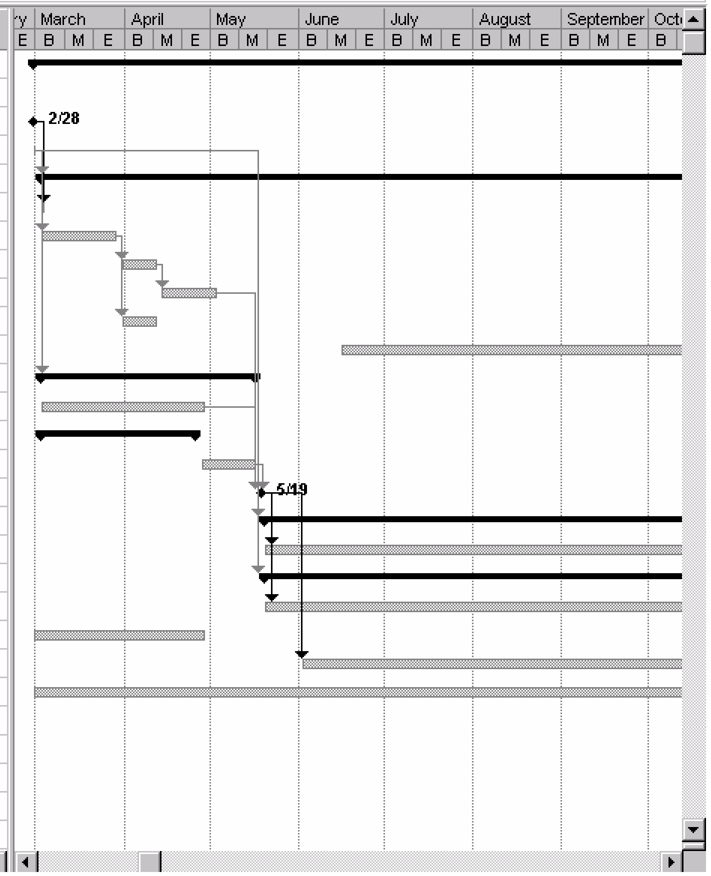
From approval SCE expects to offer the program no later than June 1, 2003. Customer recruiting efforts will continue throughout the summer.

V.B. (11) OTHER IMPLEMENTATION ISSUES

None

Table 8: Real Time Pricing – Market Index Program Proposed Implementation Plan

	Task Name	Duration	Start	Finish
1	Real Time Pricing Program	261 days	Fri 2/28/03	Fri 2/27/04
2				
3	Obtain Approval for Program	1 day	Fri 2/28/03	Fri 2/28/03
4	Determine what the Market Index will be and how to access the Market Index	1 day	Fri 2/28/03	Fri 2/28/03
5	Customer Education	260 days	Mon 3/3/03	Fri 2/27/04
6	Identify target customers for Real Time Pricing – Market Index Program	1 day	Mon 3/3/03	Mon 3/3/03
7	Develop Marketing Materials	20 days	Mon 3/3/03	Fri 3/28/03
8	Rep Training Sessions	10 days	Mon 3/31/03	Fri 4/11/03
9	Customer Training Sessions	15 days	Mon 4/14/03	Fri 5/2/03
10	Distributions of Marketing Materials to Customers, Reps, and websites	10 days	Mon 3/31/03	Fri 4/11/03
11	Ongoing Customer Program Management Letters	185 days	Mon 6/16/03	Fri 2/27/04
12	Design and Develop Processing Changes	55 days	Mon 3/3/03	Fri 5/16/03
13	Modify Billing System	41 days	Mon 3/3/03	Mon 4/28/03
14	Develop VB Program to use Market Index data	40 days	Mon 3/3/03	Fri 4/25/03
19	Train RTP Analysts on New Processes	15 days	Mon 4/28/03	Fri 5/16/03
20	*Implement Real Time Pricing into Production*	*1 day*	*Mon 5/19/03*	*Mon 5/19/03*
21	Program/Project Management	163 days	Tue 5/20/03	Thu 1/1/04
22	Program/Project Management	163 days	Tue 5/20/03	Thu 1/1/04
23	Customer Recruiting	153 days	Tue 5/20/03	Thu 12/18/03
24	Ongoing Customer Education	153 days	Tue 5/20/03	Thu 12/18/03
25	Develop Rate Analysis Tool	42 days	Fri 2/28/03	Mon 4/28/03
26	Program Evaluation	153 days	Mon 6/2/03	Wed 12/31/03
27	Conduct Customer Focus Groups	219 days	Fri 2/28/03	Wed 12/31/03



V.C. PG&E RTP/CPP Proposal for Large Customers

V.C. (1) GENERAL DESCRIPTION

PG&E's RTP/CPP proposal for large customers is a voluntary alternative dynamic pricing tariff for payment of the "three-cent" surcharge rates first adopted by the CPUC in D.01-05-064. PG&E's proposal is designed to be revenue-neutral for rates across the entire four-month period between June 1 and September 30 (i.e., a customer might pay more than under the standard tariff during some billing cycles, but less in others). The tariff includes certain elements of a two-part RTP rate, but without requiring the use of customer baseline measures or dependence on real-time market indices for program implementation and operation.

PG&E's proposal is based on a three-tiered system of daily price profiles ("low," "medium," and "high") for the Energy Procurement Surcharge (EPS) component of customer bills. These price profiles would be established in advance, together with a specific allocation of the number of times each price signal would be applicable.

PG&E has developed illustrative rate designs and example customer bill analysis information (Appendix E of this report) for its proposal, based on the assignment of 14 high-price, 28 mid-price, and 42 low-price weekdays to the four-month period between June 1 and September 30. Participants would pay significantly higher surcharge rates on the 14 assigned high-price weekdays, while having the opportunity to pay substantially discounted surcharges on the much larger number of low-price weekdays and on weekends and holidays. Current rates would be left unchanged on the moderate number of mid-price weekdays.

V.C. (2) ELIGIBILITY

This program would be offered and available to all large bundled service customers (those with at least 200 kW of maximum demand) currently served on PG&E's electric rate Schedules A-10, E-19, and E-20. Nearly all of these customers have already received the interval meters that would be needed to participate, through last year's AB1x29 metering program. (A small number of additional meters might need to be installed for those participants with loads that did not qualify for meters during the AB1x29 implementation period.) Any additional equipment requirements needed for receipt of the day-ahead price notifications would be relatively modest, because the only information that would need to be transmitted is which price profile (high, medium, or low) is to be applicable for the next day's usage.

Because this alternative tariff would be applicable only to the Energy Procurement Surcharge component of customer bills, there is no overlap with the rate structure for PG&E's existing non-firm rate program, and customers could participate in both programs. However, the program would not be applicable for direct access service, because DA customers do not pay the Energy Procurement Surcharge.

V.C. (3) SOURCE OF DRIVERS/TRIGGERS

Participants would be notified of the applicable price profile on a day-ahead basis, with the day-ahead selection of applicable price signals to be based in large part on forecasted weather and load conditions for following day. (If adequate day-ahead market information becomes available, such information could also be incorporated in the selection of the applicable price profiles.) Participants would be able to plan for and expect that the highest price signals will be applied on the warmest summer weekdays, and might continue for several days during extended heat waves. An example pricing calendar based on Summer 2001 loads is provided on the first page of Appendix E.

V.C. (4) INTENDED LEVEL OF PARTICIPATION

This program would be offered and available to all of the large bundled service customers with at least 200 kW of maximum demand that are currently served on PG&E's electric rate Schedules A-10, E-19, and E-20. Setting aside those customers in these rate groups who currently receive direct access service, this group of customers accounts for approximately 4,000 MW of aggregate load on typical summer peak days.

PG&E recommends that this program be implemented on a voluntary basis, and believes that 1,000 MW of enrolled load (representing a 25% participation rate) is a conservative upper bound on the number of customers and amount of load that could be successfully recruited to participate in this program. If the participating customers contributed an average of 15% load reductions across all of the high-price operating days, this would result in 150 MW of new demand response.

V.C. (5) SOURCES/LEVELS OF COSTS

PG&E would incur a certain amount of one-time incremental start-up costs to implement this program, largely for metering, billing system modifications (e.g., programming, account set-up, account maintenance, testing, data retrieval and preparation) and customer recruitment. Final estimates for this cost category will be provided in the December 13 report, which will address marketing and customer education considerations.

In addition to the one-time start-up costs, two different kinds of revenue shortfall costs will need to be considered for new demand reduction programs: (1) the "structural" or "self-selection" savings that may occur because some customers will always be able to benefit under a new rate option, without actively modifying their loads (even when the underlying rate design is revenue-neutral on a class average basis), and (2) the "dynamic" bill savings that result when customers do change their loads in response to the new prices.

Based on the information presented in Appendix E and as discussed at the November 1 Working Group 2 meeting, PG&E has estimated the self-selection revenue risk for its RTP/CPP program proposal to be approximately $4 per kW of enrolled load, and estimates that the dynamic bill savings available under the program would be approximately $50 per kW of average dynamic load reduction.

If customers with 1000 MW of aggregate load elect to participate in the program and this group of customers is able to consistently shed 150 MW of that load on the highest-price summer weekdays, PG&E estimates that the resulting revenue reduction associated with self-selection savings would be $4 million (1000 MW times $4 per kW), and that the bill savings associated with this level of dynamic load reduction would be approximately $7.5 million (150 MW times $50 per kW).

Under these assumptions the total cost associated with reduced revenues would be $11.5 million, at a per-unit cost of approximately $75 per kW ($11.5 million divided by 150 MW). This per-unit cost estimate would rise if participants turn out to reduce less than 15 percent of their enrolled load, and would fall if more than 15 percent of the enrolled load is actually shed.

V.C. (6) METHOD OF COST RECOVERY

PG&E proposes that a balancing account be established to track the incremental one-time "set-up" and on-going costs related to billing system modifications and customer recruitment. This approach will leave a good deal of flexibility as the final demand response programs are designed and implemented for the larger customers.

PG&E believes that its current balancing account mechanisms are adequate for recovery of the customer bill savings that will result if this program proposal is implemented. If the program is successful, PG&E would expect the revenue reductions associated with both customer self-selection and dynamic bill savings to be somewhat offset by changes in the quantity and/or types of procurement products or spot market purchases that will need to be made on behalf of all customers. (If the program does not prove to be successful, it should not be extended for future years.) For PG&E, the current Emergency Procurement Surcharge Balancing Account (ESPBA) and the Transition Revenue Accounting (TRA) mechanisms record the actual costs of procurement products and spot market products. Additionally, the current TRA mechanism ensures that full collection of PG&E's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue under-collections of the type described here. PG&E will seek similar accounting mechanisms once the TRA is no longer in place.

V.C. (7) LINKAGE TO PROCUREMENT ACTIVITIES

As noted above, if the program is successful, PG&E would expect the revenue reductions associated with customer bill savings to be offset by changes in the quantity and/or types of procurement products or spot market purchases that will need to be made on behalf of all customers.

V.C. (8) ESTIMATED START DATE

PG&E's proposal is for a four-month program, with rates to be effective during the period between June 1 and September 30, 2003.

V.C. (9) PROPOSED METHOD OF IMPLEMENTATION

PG&E's program would be implemented as a set of alternative procurement surcharge rates to be offered under Section 2 of its rate Schedule E-EPS.

V.C. (10) LEAD TIME FROM APPROVAL

Provided that a final Phase 1 decision and complete rate design are in place by early February, PG&E believes there would be adequate time during the spring of 2003 to educate customers and recruit participants for the June 1 start date.

V.C. (11) OTHER IMPLEMENTATION ISSUES

PG&E has made its rate design model and supporting customer load profile data available to CEC technical staff, and is engaged in ongoing analysis based on discussions at the November 1 Working Group 2 meeting. To the extent that this additional analysis (or additional input from interested customers and their representatives) produces revised recommendations for the final rate design parameters shown at the second page of Appendix E, this will be addressed in an appropriate section of the December 13 report.

PG&E has noted elsewhere that there are no remaining customers enrolled under its existing experimental real-time pricing tariff, Schedule A-RTP, and would view this program as a reasonable successor to that tariff. Therefore, and as a clean-up matter, PG&E requests that the final Phase 1 decision in this rulemaking authorize cancellation of PG&E's pre-existing Schedule A-RTP.

V.D. ACWA Customer Critical Peak Pricing Proposal (CPP)

V.D. (1) GENERAL DESCRIPTION

Electricity customers in California are wary. We have seen tremendous whipsaws in the wholesale electricity market prices over the last several years. We are understandably cautious about any new proposal that will subject us to prices that are volatile, unpredictable, and can be manipulated by forces outside of our control.

However, we do understand that the utilities are entering a new phase in their procurement history, and that demand responses can be quite favorable compared to generation options in terms environmental impacts, flexibility, locational control, and prices.

This proposal is intended to meet the need for more flexibility and response from the demand side, while not exposing to the volatility and the risk of the wholesale energy market.

We have developed three criteria for evaluating potential new demand response programs: 1) there is little or no risk for customers, 2) it is easy to understand, 3) it is not expensive (in terms of personnel or hardware) to implement. We do not want to be exposed to the risk of the wholesale market, at least until we see some stability and predictability in the prices in that market. We need a program that is relatively easy to understand. Quite frankly, we do not completely understand how prices have been set in the wholesale energy market. And lastly, we don't want to spend a lot of time, energy, and money on a complicated program that we don't know will work or not.

This proposal is quite simple. Take a portion of the component of existing demand charges, and collect it not based upon an instantaneous monthly peak, but rather a portion of it based upon demand during the critical peak period. This will encourage customers to reduce demand during the critical peak periods. Furthermore, if a number of critical peak hours occur during a month, provide an energy incentive for customers to continue to reduce demand.

In this proposal, a portion of existing demand charges are based upon the customers demand during the utility-called Critical Peak Pricing (CPP) hours of the month. This is an option on an existing utility tariff, so it is very easy for customers to understand. It is also simple and easy to implement, the customer just as to pay attention to their demand during the critical peak pricing hours.

Key features of this rate option are:
- they implicitly or explicitly include approximately a $1.00 -1.50 /kWh credit on customer's bills for reducing demand during Critical Peak Hours,

- customers can do no worse on these rates than their current rates (which we believe is important to attract customers),
- it is simple for customers to understand – basically a supplement to an existing tariff,
- it is inexpensive for customers to implement, not requiring additional hardware or personnel,
- it provides an incentive for non-firm or interruptible customers to participate as well as firm service customers,
- it is compatible with the CPA's Demand Reserves Partnership (CPA DRP) so that customers who are willing to make firm commitments to demand reduction and who can participate in the ISO ancillary service markets can participate on both this CPP and CPA DRP and receive incremental benefit,
- a major part of the price signal is similar to the way of calculating billing demand under the A6-TOU rate used by SDG&E, and
- a balancing account would insure that utilities costs are recovered from other large customers.

This customer proposal has the opportunity for, on average, customers annually to receive a credit of about $36 per kW of load reduction. This is clearly quite cost-effective compared to current generation capacity costs ($80/kW). Since customers can also participate in the CPA DRP and provide incremental benefit, they have the opportunity to receive additional credits.

CPP is an option within the existing customer tariffs (e.g., a rider on A10, E-20, TOU-8, or GS-2). It is characterized by two major components:
- adjustment in billing demand calculation under the existing rates based on the customers average hourly demand during the Critical Peak hours of use in a summer month – and the utility will call at least 6 Critical Peak hours each summer month,
- after the first six Critical Peak Hours, an approximately $1.00/kWh credit ($1.50 for customers less than 500 kW peak demand) during all Critical Peak Hours for each kWh reduced below the monthly average hourly kWh use during the Peak Period.

Here are two examples for how the first component would work and then two examples of how the second component would work

Examples:

Component One – Revised Billing Demand Determination

PG&E A-10 CPP Secondary Voltage Example
The monthly demand charge is $6.70/kW. This customer's entire demand charge is based on their demand during the Critical Peak Hours of the month. Since most months we expect the utility to use the program 6 hours, the $6.70/kW demand charge divided by 6 hours yields an implicit price of $1.12/kWh.

The utility shall declare the afternoon before when such hours will be in effect. If an A10 customer's normal summer month peak demand is 400 kW and they reduce it to an average of 320 kW during the six Critical Peak Hours of the month, then that customer will have lowered their billing demand by 80 kW and lowered their total bill for that month by $536 (= 6.70 * (400 –320)).

<u>PG&E E-20 Firm Service Secondary Voltage</u>
The monthly demand charge is $13.35/kW. This customer's (secondary service) billing demand will be 50% based on their normal maximum peak period demand during the month and 50% on their hourly average demand during the first 6 Critical Peak Hours of the month.

Assume this customer's normal maximum peak period demand is 4000 kW and that during the first 6 Critical Peak Hours they can lower that to an average of 3200 kW. Then the new billing demand is 3600 kW (= (50%)*(4000 kW) + (50%) * 3200 kW). Their new monthly demand charge is now $48,060 (3600kW*$13.15/kW), while their old demand charge was $53,400 (4,000kW*$13.35/kW). The customer monthly bill is now $5340 lower (= (4000 kW normal billing demand – 3600 kW new billing demand) * ($13.35)).

Component Two – Energy Credit (after the six CPP hours are used up and for nonfirm customers)

While we expect that the utility will not normally invoke more than six Critical Peak hours a month, we need a mechanism to encourage customers to decrease demand in additional hours if needed. Situations may arise where the utility needs more critical peak hours (e.g., if the utility expects the ISO to declare a Stage 1 condition). In such conditions, it is desirable to incent the customers to reduce demand for these additional hours. In addition, for some customers with minimal monthly demand charges (e.g., E-20 non-firm service at transmission voltage), this component is used in all Critical Peak hours. Two examples are provided below.

<u>A10 CPP Secondary Voltage</u>

Assume a month in where the utility called 10 CPP hours. The utility was able to use its allotted 6 Critical Peak hours during 6 of the 10 CPP hours. Then the utility invoked the other 4 hours as Critical Peak hours. During these 4 hours, the energy credit component would apply.

For the A10 customer above, assume they used 42,000 kWhs during a summer month Peak Period that had 120 Peak Period hours. That means this customer's average hourly consumption during the Peak Period was 350 kW. If the customer continues to reduce demand during these additional 4 hours to 320 kW, the customer receives an additional payment of $1.50/kWh or $180 (= 4 hrs * $1.50 * (350 kW – 320 kW)).

Three observations. First, a customer with a lower load factor, may have to reduce some load just to bring the load down to 350 kW on that day. However, such a customer probably also benefited proportionately more from having the Component One Demand Charge based on the average hourly Critical Peak hours demand. Moreover, the energy payment is set higher ($1.50) for smaller (< 500 kW) customers to help off-set this. Second, since the Monthly Billing Demand is based on all Critical Peak Hours, they will have motivation to reduce demand during these 4 hours even if they cannot get demand below the hourly average during the monthly peak period. Third, the customer will still not pay a higher bill if they cannot reduce down to their monthly average consumption level.

E-20 Firm Service Secondary Voltage

For the E-20 customer, assume their total monthly peak period consumption is 456,000 kWhs for 120 peak period hours. This is an average hourly demand of 3800 kW (= 456,000 kWh/120 hours) during the peak period for the month. If the customer is able to reduce demand to 3200 kW during these 4 additional hours, then the customer will get an additional monthly savings of $2400 (= 4 hrs * $1.00/kWh * (3800 kW – 3200 kW)).

Note that also the customer has great incentive not to increase demand during these 4 additional hours. Their total demand charge is partially based upon their average use during the critical peak hours. After the initial six hour level is set, any incremental increases in demand during these 4 additional hours erodes the customer's prior savings.

Attached are the necessary changes in the PG&E and Edison tariffs to implement this program.

V. D. (2) ELIGIBILITY

Any bundled service end users of the Investor-Owned Utilities that qualify for the main tariffs (e.g., A10, E-20, GS-2, and TOU-8) would be eligible to participate in this option of those tariffs.

V. D. (3) SOURCE OF DRIVERS/TRIGGERS

The IOU will determine the Critical Peak Periods, with a minimum of 6 hours per month during each summer month. These Critical Peak Periods will typically be called during expected low reserves, local transmission problems, very high wholesale spot market prices, or monthly system peak.

V. D. (4) INTENDED LEVEL OF PARTICIPATION

Participation in this option is available to anyone who qualifies for the existing tariff. This option would be available to any customers who wish to migrate from existing utility interruptible tariffs.

V. D. (5) SOURCES/LEVELS OF COST

A portion of existing demand charges (about $36/kW-year) are based upon the customers demand during the utility-called Critical Peak Pricing (CPP) hours of the summer months. If more than six Critical Peak Hours are needed in any month, an approximately $1.00/kWh credit ($1.50 for customers less than 500 kW peak demand) during all Critical Peak Hours for each kWh reduced below the monthly average hourly kWh use during the Peak Period.

V. D. (6) METHOD OF COST RECOVERY

Any net revenue reductions, after avoided cost savings, would be collected in a balancing account.

V. D. (7) LINKAGE TO PROCUREMENT ACTIVITIES

After the IOU establishes some experience on the level of demand reduction from this rate option, the IOU will include this demand reduction in its procurement plans.

V. D. (8) ESTIMATED START DATE

When the utilities shift to summer billing (May or June 2003).

V. D. (9) PROPOSED METHOD OF IMPLEMENTATION

This program will be implemented using utility bill inserts and customer service representatives. We also commend that the utilities contract with customer groups (e.g., ACWA, CMTA, CLECA, etc.) to provide marketing materials to their

V. D. (10) LEAD TIME FROM APPROVAL

There may be several months lead time for the IOUs to adapt their billing systems to account for the Critical Peak pricing hours, and to market the program to customers. Regardless, this program should be operational by the beginning of Summer 2003.

V. D. (11) OTHER IMPLEMENTATION ISSUES

The terms on which customers can participate simultaneously on this program and other dynamic pricing and demand response options without double counting benefit needs to be clarified.

V.D. (12) ALTERNATIVE PERSPECTIVES

AECA Alternative Perspective

The AECA would like to request that the CPP Proposal for Large Customers be modified to extend to agricultural water pumpers. As with the industrial and commercial customers, agricultural users and pumpers are highly sensitive to the increased costs of operation associated with historically high electricity rates. This is particularly true in Southern California Edison Company's territory, where large agricultural pumpers have experienced disproportionately high rate increases relative to the rest of the state. And unlike Edison's large industrial and commercial users, who can look forward to rate decreases as a result of Edison's 2003 General Rate Case proceeding (02-05-004) many agricultural customers in Southern California Edison service territory are threatened with substantial rate increases in the same application. As a result, agricultural customers and large agricultural pumpers are eager to take advantage of cost-effective critical peak pricing tariffs. The ACWA proposal should be available in all service areas.

PG&E Alternative Perspective

PG&E does not believe the ACWA CPP proposal should go forward as currently formulated. As currently formulated, every bundled service PG&E customer with at least 200 kW of load and an interval meter would be eligible to enroll under ACWA's proposed program. It would in fact be advisable for all of PG&E's such customers to enroll, given that the proposal is formulated as a "no losers" rate program – there would be no need to go forward with any of the other dynamic pricing programs that have been considered by WG2, because the ACWA proposal would offer lower effective bills than any of the other proposed pricing programs. PG&E is concerned that, were ACWA's proposal to be implemented, large revenue undercollections would accrue for future recovery in ACWA's recommended balancing account, and this would happen regardless of whether any new demand reductions are contributed by customers enrolled under such a program. Revenue reductions that are not matched by corresponding demand reductions would contribute none of the offsetting purchased power savings that would leave other ratepayers harmless.

SCE Alternative Perspective

SCE agrees with the comments of PG&E on the ACWA proposal, but would like to make an additional point. SCE currently has a tariff that is similar to the rate structure in the ACWA proposal, without the artificial rate reductions identified by PG&E, called TOU-8-RTP. This tariff determines essentially defines the peak period for purposes of billing as being the hours during the normal system peak when the temperature exceeds a certain level. The peak demand is calculated as the energy usage during that peak period divided by the number of peak hours. This has the effect of defining critical periods based on temperature, and providing customers the same opportunity to reduce their loads and bills in the same manner as proposed by ACWA. SCE further notes that no customers ever took this service.

ACWA PROPOSED PG&E TARIFF CHANGES FOR CPP

E-20

11. Non-Firm Service Program

add:

a. Customers on this program may also participate in the Demand Bidding Program or the Demand Reserves Partnership of the California Power Authority. Customers participating on the Demand Bidding Program will not be eligible for energy payments during the hours of requested curtailment. Customers participating on the Demand Reserves Partnership are eligible for capacity payments on the Partnership program only for an amount not to exceed the Firm Service Level under this program. In addition, the customer cannot receive any energy payments under the Demand Reserve Partnership during the hours of curtailment under this program.

SPECIAL CONDITIONS – add a new section:

18. CRITICAL PEAK PRICING ADJUSTMENT OPTION.

Customers may select the Critical Peak Pricing Adjustment Option. Under this option, during all Summer months, the Billing Demand for the Peak Period will be a weighted combination of the Maximum Demand (as defined in section 1) and the average demand during the Critical Peak Hours. The Critical Peak Hours are hours in which PG&E declares a Critical Peak Condition due to high peak demand, high wholesale market prices and/or low reserves. At a minimum PG&E will declare at least six Critical Peak Hours each summer month.

The mix of Maximum Peak Period Demand and Critical Peak Hour average demand used to compute the Billing Demand applied to the Maximum Peak Period Demand Charge is:

	% Maximum Peak Period Demand	% Critical Peak Hour Avg Demand
Firm Service at these voltage levels		
Transmission	20%	80%
Primary	40%	60%
Secondary	50%	50%
Non-Firm Service at these voltage levels		
Transmission		Not Applicable
Primary	0%	100%
Secondary	0%	100%

In addition, if PG&E declares more than six Critical Peak Hours in a given Summer month (or declares any Critical Peak Hours in a given Summer month for transmission level non-firm service), then in all such Critical Peak Hours, customers will be credited $1.00/kWh for each kWh by which the Hourly Average Demand during the monthly Peak Period exceeds the Critical Period Hourly Demand.

PG&E will not declare a Critical Peak Condition for longer than four hours per day, nor for less than two consecutive hours duration, nor more than one Critical Peak Condition per day, nor more than 40 hours per month, nor more than 30 days per year. The customer will receive an email and pager notification by 3 pm the day before, in which the notification will state the hours in which the Critical Peak Conditions are in effect.

Both Firm Service and Non-Firm Service customers are eligible for this Option. Customers may also participate on PG&E's Demand Bidding Program or the Demand Reserve Partnership of the California Power Authority, but will be ineligible for any energy payments on those programs during Critical Peak Hours on this Option.

Customers will enroll in this Option for a minimum of one year and can renew annually between November 1 and December 1. First-time participants may enroll at any time.

SCHEDULE A-10—MEDIUM GENERAL DEMAND-METERED SERVICE
(Continued)
RATES: (Cont'd.)

Generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Program, Nuclear Decommissioning, and FTA (where applicable) charges. CTC is calculated residually by subtracting the PX charge as calculated in Schedule PX from the generation charge. (N)
The above rate components apply to those customers eligible for the Rate Reduction Bond Credit. For those ineligible for the credit, the Generation component will be equal to the Generation component listed above plus the FTA component. (N)

BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. (L)
SPECIAL CASES: (1) If the customer's maximum demand has exceeded 400 kW for three consecutive months, 30-minute intervals will be used for averaging. The customer will be returned to 15-minute intervals when its maximum demand has dropped below 300 kW and remains there for 12 consecutive months. (2) If the customer's use of energy is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used. (3) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of Rule 2. (L)

CRITICAL PEAK PRICING ADJUSTMENT OPTION.

Customers may select the Critical Peak Pricing Adjustment Option. Under this option, during all summer months, the Billing Demand equals the average demand during the Critical Peak Hours. The Critical Peak Hours are hours in which PG&E declares a Critical Peak Condition due to high peak demand, high wholesale market prices and/or low reserves. At a minimum, PG&E will declare at least 6 Critical Peak Hours each summer month.

In addition, if PG&E declares more than 6 Critical Peak Hours in a given Summer month, then in all such Critical Peak Hours, customers will be credited $1.50/kWh for each kWh by which the Hourly Average Demand during the monthly Peak Period exceeds the Critical Period Hourly Demand.

PG&E will not declare a Critical Peak Condition for longer than four hours per day, nor for less than two consecutive hours duration, nor more than one Critical Peak

Condition per day, nor more than 40 hours per month, nor more than 30 days per year. The customer will receive an e-mail and pager notification by 3 pm the day before, in which the notification will state the hours in which the Critical Peak Conditions are in effect.

Customers may also participate on the Demand Bidding Program or the Demand Reserve Partnership of the California Power Authority, but will be ineligible for any energy payments on those programs during Critical Peak Hours on this Option.

Customers will enroll in this Option for a minimum of one year and can renew annually between November 1 and December 1. First-time participants may enroll at any time.

ACWA PROPOSED EDISON TARIFF CHANGES FOR CPP

TOU-8 SPECIAL CONDITIONS

CRITICAL PEAK PRICING ADJUSTMENT OPTION.

Customers may select the Critical Peak Pricing Adjustment Option. Under this option, during all Summer months, the Time-Related Component of the On-Peak Billing Demand will be a weighted combination of the Maximum Demand (as defined in section 3) and the average demand during the Critical Peak Hours. The Critical Peak Hours are hours in which Edison declares a Critical Peak Condition due to high system peak demand, high wholesale market prices and/or low reserves. At a minimum Edison will declare at least six Critical Peak Hours each summer month.

The mix of Maximum On-Peak Billing Demand and Critical Peak Hour average demand used to compute the Time-Related Component of the monthly On-Peak Billing Demand applied to the On-Peak Billing Demand Charge is:

	% Maximum On-Peak Billing Demand	% Critical Peak Hour Avg Demand
Transmission	40%	60%
Primary	50%	50%
Secondary	50%	50%

In addition, if Edison declares more than six Critical Peak Hours in a given Summer month (or declares any Critical Peak Hours in a given Summer month for transmission level non-firm service), then in all such Critical Peak Hours, customers will be credited $1.25/kWh for each kWh by which the Hourly Average Demand during the monthly Peak Period exceeds the Critical Period Hourly Demand.

Edison will not declare a Critical Peak Condition for longer than four hours per day, nor for a duration of less than two consecutive hours, nor for a duration of less than two consecutive hours, nor more than one Critical Peak Condition per day, nor more than 40 hours per month, nor more than 30 days per year. The customer will receive an e-mail and pager notification by 3 pm the day before, in which the notification will state the hours in which the Critical Peak Conditions are in effect.

Customers may also participate on Edison's Demand Bidding Program or the Demand Reserve Partnership of the California Power Authority, but will be ineligible for any energy payments on those programs during Critical Peak Hours on this Option.

Customers will enroll in this Option for a minimum of one year and can renew annually between November 1 and December 1. First-time participants may enroll at any time

SPECIAL CONDITIONS (Continued)

16. Generation Charge: The generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Programs, Nuclear Decommissioning, and Fixed Transition Amount (where applicable) charges, the Transmission Owners Tariff Charge Adjustments (TOTCA), and the Public Utilities Commission Reimbursement Fee.

17. Critical Peak Pricing Adjustment Option.

Customers may select the Critical Peak Pricing Adjustment Option. Under this option, during all summer months, the Time Related Component of the Billing Demand equals the average demand during the Critical Peak Hours. The Critical Peak Hours are hours in which Edison declares a Critical Peak Condition due to high system peak demand, high wholesale market prices and/or low reserves. At a minimum, Edison will declare at least 6 Critical Peak Hours each summer month.

In addition, if Edison declares more than 6 Critical Peak Hours in a given Summer month, then in all such Critical Peak Hours, customers will be credited $1.50/kWh for each kWh by which the Hourly Average Demand during the monthly Peak Period exceeds the Critical Period Hourly Demand.

PG&E will not declare a Critical Peak Condition for longer than four hours per day, nor for a duration of less than two consecutive hours, nor more than one Critical Peak Condition per day, nor more than 40 hours per month, nor more than 30 days per year. The customer will receive an e-mail and pager notification by 3 pm the day before, in which the notification will state the hours in which the Critical Peak Conditions are in effect. If the ISO declares a Stage 1 alert after Edison issues the day ahead notification, Edison will declare the appropriate Critical Peak Hours at such time as the alert is issued.

Customers may also participate on Edison's Demand Bidding Program or the Demand Reserve Partnership of the California Power Authority, but will be ineligible for any energy payments on those programs during Critical Peak Hours on this Option.

Customers will enroll in this Option for a minimum of one year and can renew annually between November 1 and December 1. First-time participants may enroll at any time.

V.E. Joint Utilities Demand Bidding Program Proposal

V.E. (1) GENERAL DESCRIPTION

Target Market

Commercial/industrial bundled service customers served by the PG&E or SCE or SDG&E (the Utilities) who are 200 kW and above (300 kW and above for SDG&E), and who have an interval meter capable of recording metered data on a 15 minute interval. Customers must be able to access the program's website to participate in the Program and be able to determine in advance the amount of load (minimum of 100 kW) they are able to curtail in each one-hour period of the event.

Approach

This proposed Demand Bidding Program (DBP) modification allows participants to voluntarily reduce demand when requested by the Utilities in one of two ways; 1) ***Price Trigger*** - when the California Independent System Operator (CAISO) Day-Ahead or Day-Of market price (or proxies) equals or exceeds $0.15- per kWh for any hour between 12pm and 8 pm weekdays only, excluding weekends and holidays; or 2) ***System Emergency Trigger*** - when the CAISO issues either an 'Alert' notification or a 'Warning' notification when system reserves are forecast to be 7% or less between the hours of 12 pm and 8 pm weekdays only, excluding weekends and holidays. Participants receive a bill credit equal to either; 1) the product of the forecast hourly market price which will be equal to or greater than $0.15 per kWh and the qualified kWh reduction for each hour for which a DBP bid is accepted for a price triggered event; or 2) $0.35 per kWh of qualified reduction for each hour for which a DBP bid is accepted for a system emergency triggered event.

V. E. (2) ELIGIBILITY

Customer must be a bundled service customer served by the Utilities who is not receiving electric service under the Hourly PX Pricing (HPX) Option of any rate schedule or any Real Time Pricing (RTP) and can reduce their electric demands by at least 100 kW during a DBP event. Customers served by the Utilities on agricultural rate schedules are ineligible to participate in the DBP program. In order to participate, customers must be at least 100 kW and above and have interval metering capable of recording usage in 15-minute intervals and Internet access in order to bid and receive notification of DBP Events.

V.E. (3) SOURCE OF DRIVERS/TRIGGERS

Source of Price Triggered DPB Event

Forecasted hourly prices for the day-ahead market are posted by the CAISO by 2 pm. Forecasted hourly prices for the day-of market are posted by the CAISO by 11 am. These markets are expected to be operational in early 2003 as a result of the FERC order of July 17, 2002.

Source of Emergency Triggered DBP Event

The CAISO will issue either an 'Alert' notification or greater (Warning, Stage I, II or III) by 2:00 pm the day before the event or a 'Warning' notification or greater (Stage I, II, or III) by 11:00am the day of the event when system reserves are forecast to be less than 7%.

Specific Tariff/Program Elements

Events can be called any weekday (excluding holidays as defined by the Utilities) between the hours of 12:00 pm and 8:00 pm. The DBP offers two bidding options: the Day-Ahead bidding option and the Day-Of bidding option. The Program is triggered when the forecast market price is $0.15 per kWh or greater or when system reserves are forecast to be less than 7%.

The Utilities activate the DBP Day-Ahead bidding option or event when if by 2:00 pm; 1) the CAISO Day-Ahead market price is forecast to equal or exceed $0.15 per kWh during any hour between 12:00 pm and 8:00 pm the next day; or 2) the CAISO issues an "Alert" or a more advanced notice (Warning, Stage I, II, or III emergency notice) for the following day between the hours of 12:00pm – 8:00pm. DBP Day-Ahead events will occur between 12:00 pm and 8:00 pm the next day if the CAISO does not specifically identify the hours of operation for the event. A participating customer may log into the program's website and place an energy bid between 3:00 pm and 4:00 pm on the day before the DBP Event.

The Utilities activates the DBP Day-Of bidding option or event when if by 11:00 a.m.; 1) the CAISO Day-Of market price is forecast to equal or exceed $0.15 per kWh during any hour between 3pm and 8 pm on that day; or 2) the CAISO issues a "Warning" or a more advanced notice (Stage I, II, or III emergency notice) on that day. DBP Day-Of events will occur between 3:00 pm and 8:00 pm if the CAISO does not specifically identify the hours of operation of the Day Of event. A participating customer may log into the program's website and place an energy bid between 12:00 noon and 1:00 pm on the day of the DBP Event.

Calculation of the Incentive

The incentive payment for an event will be calculated based on whether the event was a price trigger or system emergency triggered event. There can only be one trigger per day. For example, there cannot be a Day Ahead price-triggered event and a Day Ahead emergency condition event triggered for the same day. For a price triggered event the incentive payment for each hour of load curtailment is equal to the forecast hourly market price (when the forecast market price is equal to $0.15 per kWh or greater) times the customer's qualified kWh reduction. For a system emergency triggered event the incentive payment for each hour of the load curtailment is equal to the $0.35 times the customer's qualified kWh reduction.

A participant cannot bid in more than one event per day and/or receive more than one incentive payment for the same event. . For example, if a customer who has submitted a bid in a Day Ahead event on a Monday (for Tuesday's event) will not also be able to bid in a Day Of event issued on Tuesday for that same day. In order to qualify for payment for any hour of a DBP event, the customer must curtail at least 50% of their energy bid amount. Customers will only be paid for a maximum of 150% of their accepted energy bid amount. Credit payments are determined on an hourly basis. Credit will appear on bills within 90 days after a DBP event.

There are no penalties for failing to reduce power after submitting a bid or choosing not to submit a bid. However, if an interval meter was provided to the customer at no charge and the customer does not fully comply with the minimum DBP bid requirements of participating in the first ten (10) DBP Events during the first year (provided at least 10 events are called in a year), then the customer must reimburse the serving Utility for the meter costs.

How To Submit a Bid

The customer must submit bid commitments to reduce power via the program's Internet website. The customer needs a user ID and password to access the website. Once the customer logs on, they will be able to view the time period for the specific DBP event for which bids are being accepted. If the CAISO has issued an "Alert" notice (or a more advance notice) or if the CAISO has posted a market price equal to greater than $0.15 per kWh for any hour of the event the next day, this information will be available to the customer on the program's website by 3:00 pm. Customers may bid between 3:00 pm and 4:00 pm for an Emergency triggered or price triggered event between 12:00pm – 8:00pm the next day. Notice of bids accepted will be available on the website after 5:00 pm.

If the CAISO has issued a "Warning" notice (or a more advance notice) or if the CAISO has posted a Day-Of market price equal to or greater than $0.15 per kWh for any hour from 3 pm to 8 pm, this information will be available that day on the program's website by 12 noon. Customers may bid between 12 noon and 1 pm on the day of the DBP Event. Notice of bids accepted will be available on the program's website after 2 pm.

Determination of the Customer's Load Reduction

In order to determine how much energy the customer actually reduces, the Utilities must know what the usage would have been before the customer reduces power. This Customer Specific Energy Baseline (CSEB) is the 10-day rolling average energy usage determined on a hourly basis, using the average of energy usage for the same hour for the past 10 similar days (excluding days the customer was paid to reduce power under other demand response program or the customer was subject to a rotating outage) prior to a DBP Event. The customer's CSEB is compared to the actual amount of kWh used for that hour during the DBP Event to determine if the customer complied with the program and if the customer is eligible for the bill credit.

Customer Equipment Needed

The customer must have interval metering capable of recording usage in 15-minute intervals and Internet access to bid and receive notification of DBP Events. Internet access is the only forum to actually submit commitment to reduce load. If necessary, customers will be provided an interval meter free of charge. To receive a meter at no charge, the customer must fully comply with the minimum DBP bid requirements of participating in a minimum of the first ten (10) DBP Events in the year (provided at least 10 events occur during the year). Failure to do so will result in the customer reimbursing the serving Utility for the meter costs.

The customer must also have an email address and an electronic device (pager or cell phone) that is capable of receiving a text message sent via the Internet to receive notification. The customer is responsible for the operations and costs of these communication devices.

Contractual Requirements

The customer is required to execute an agreement with the Utility that designates service accounts, compliance with eligibility requirements and specifies notification requirements, if any.

Interaction with other Tariffs/Demand Response Programs

A DBP participant may also participate in PG&E's Interruptible Programs such as Non-Firm, E-BIP, E-PBIP, E-SLRP, OBMC and E-POBMC, SCE's Interruptible (I-6), TOU-BIP, AP-I, OBMC, SLRP, GS-APS and GS-APS_E and SDG&E's Interruptible programs including BIP and OBMC. However, the customer will not receive any credits for the DBP Event during any period that a DBP Event overlaps with an interruptible event under those programs or a rotating outage event. DBP participants may not participate in Critical Peak Pricing (CPP), HPX or RTP or the CAISO Demand Relief program or the California Power Authority's Demand Reserves Program.

SCE Specific Program Information

V.E. (4) INTENDED LEVEL OF PARTICIPATION

Participation level for the proposed Demand Bidding Program depends on the level of incentives offered to participants and the degree of certainty that participants have that they will in fact receive some compensation for participating in the program. When the Demand Bidding Program payments were under the sponsorship of the Department of Water Resources with a payments ranging up to 75 cents per kWh, the program had as many as 173 service accounts with a maximum demand of 303 MWs. However, the DWR never triggered the program. In July 2002 the CPUC authorized SCE to modify the programs to be triggered for reliability and pay participants 35 cents per kWh. The current DBP has also never been triggered. Participation has diminished since that time, which may be attributed to the lack of activity and frequent program changes. Many participant contracts have recently matured and have not been renewed. Currently participation is down to 27 service accounts with a maximum demand of 30 MWs.

SCE expects that with adequate incentive levels, multiple triggering events, and a relatively low trigger price (that will result in presumably more paying events albeit at a lower price) participation could increase to previous levels of approximately 200 service accounts with a maximum demand of 300 MWs (with a minimum bid level, assuming all participants bid, of about 20 MWs).

V.E. (5) SOURCES/LEVELS OF COSTS

The Demand Bidding Program is an existing program with essentially all the infrastructure and processes in place. The primary proposed change to the program is the addition of a price trigger. Currently DBP participants are able to view their usage, the 10-day rolling average and make bids on the existing website. SCE will utilize the same process as before, with the expectation that the ISO will post prices appropriately so that SCE can launch price-triggered events. Presently SCE does not expect to incur incremental costs related to billing system changes due to the price trigger. Due to the relatively small participation level, SCE currently calculates the DBP payments manually and enters the credit as a line item on the customer's bill. This process will continue unless participation and/ or activity increases to a level that necessitates automation.

SCE may also experience incremental costs related to printing and mailing information material reflecting the new program features for customer education and recruiting as well as for conducting participant focus groups to assess participation interest and response to the program features, incentive levels and operational issues.

SCE has no experience with the existing and predecessor DBP upon which to base an estimate of incentive payments.

Final cost estimates will be provided for the December 13, 2002 report, which will address marketing and customer education considerations as well.

V.E. (6) METHOD OF COST RECOVERY

Cost by source as well as expected cost recovery method for SCE's DBP are provided in the Table 1.

Operations & Maintenance Expenses (O&M)

SCE proposes to recover incremental O&M for each of the cost sources through a new balancing account to be established by an interim and/or final decision in this proceeding as opposed to the existing Interruptible Program Memorandum Account (ILPMA), which presently allows SCE to record incremental O&M for the DBP for future recovery. Some costs may already be recovered in current rates. An example of that is customer recruiting, which includes primarily the time of SCE account representatives who contact potential program participants and whose labor costs are already recovered in existing rates. Costs that are recovered in current rates are not quantified for purposes of program implementation. However, since the DBP is an existing program, some cost categories may have no incremental costs.

Incentive Payments

DBP incentive payments are presently recorded in the ILMPA and SCE proposes to now record these costs in a new balancing account as opposed to the existing ILPMA account.

Revenue Shortfall

When a customer reduces its energy consumption in response to a DBP event, SCE may suffer a revenue shortfall. Under the current regulatory framework, SCE does not anticipate that there will be any significant difficulties. SCE's distribution revenues are covered under an Electric Revenue Adjustment Mechanism (ERAM) type mechanism, the Electric Distribution Revenue Adjustment Balancing Account (EDRABA), so any shortfall in distribution revenues that does result will be recovered through the distribution balancing accounts. Generation revenues are also booked to an ERAM like mechanism under D.02-04-016 and D.02-10-062, the Electric Revenue Recovery Account (ERRA), and any shortfall resulting from a reduction in collection of generation related revenues from customers taking SCE's proposed DBP tariff would be reflected in those generation related balancing accounts. These two accounts insure cost recovery for distribution and generation related costs in SCE's post Settlement period.

SCE would point out that under its current Settlement ratemaking methodology, reductions in revenues will also show up as reductions in Surplus and consequently reduced contributions to the recovery of PROACT. Thus, there is the possibility that large revenue shortfalls resulting in reduced contributions to Surplus, would lead to the Settlement period being extended to the detriment of other customers. In the event that these programs are implemented prior to the end of the Settlement, and the revenue shortfalls are large, SCE would propose the following:

- book the lost net revenues to its PROACT account
- book the corresponding amounts of lost net revenue to a balancing account for later recovery.

This proposal is similar to how the Commission has treated lost baseline revenues and increased CARE costs for SCE's Settlement ratemaking. SCE does not anticipate it will be necessary to implement these procedures since these programs will not be implemented until the summer.

SCE expects to incur minimal capital costs related to the modified DBP. SCE proposes to record any revenue requirements related to capitalized costs in a balancing account to be established as a result of this proceeding.

Table 1 indicates the classification of costs for recovery purposes.

Table 9: Sources of Costs and Methods of Cost Recovery Demand Bidding Program

Cost Source	Balancing Account	Current Rates
O&M		
Billing (on-going)		X
Billing System Modifications (one-time charge)	X	X
Customer Notification (one time charge)	X	
Customer Education (on-going)		
Printing & Mailing	X	
Materials Development, Communications, web site updates		X
Program Management/Admin	X	X
Customer Recruitment		X
Program Evaluation	X	X
Customer Focus Group	X	X
Incentive Payments	X	
Revenue Shortfall	X	
Capital Costs (Rate Based)	X	

V.E. (7) LINKAGE TO PROCUREMENT ACTIVITIES

In the short term, demand response programs lead to changes in energy purchases at the margin. In the long-term, these programs are expected to be factored into the integrated resource planning and procurement processes, which will set the framework to determine the level of demand response required and achieved and the appropriate incentive levels.

V.E. (8) ESTIMATED START DATE

SCE expects to have fully operational DBP not later than June 1, 2003.

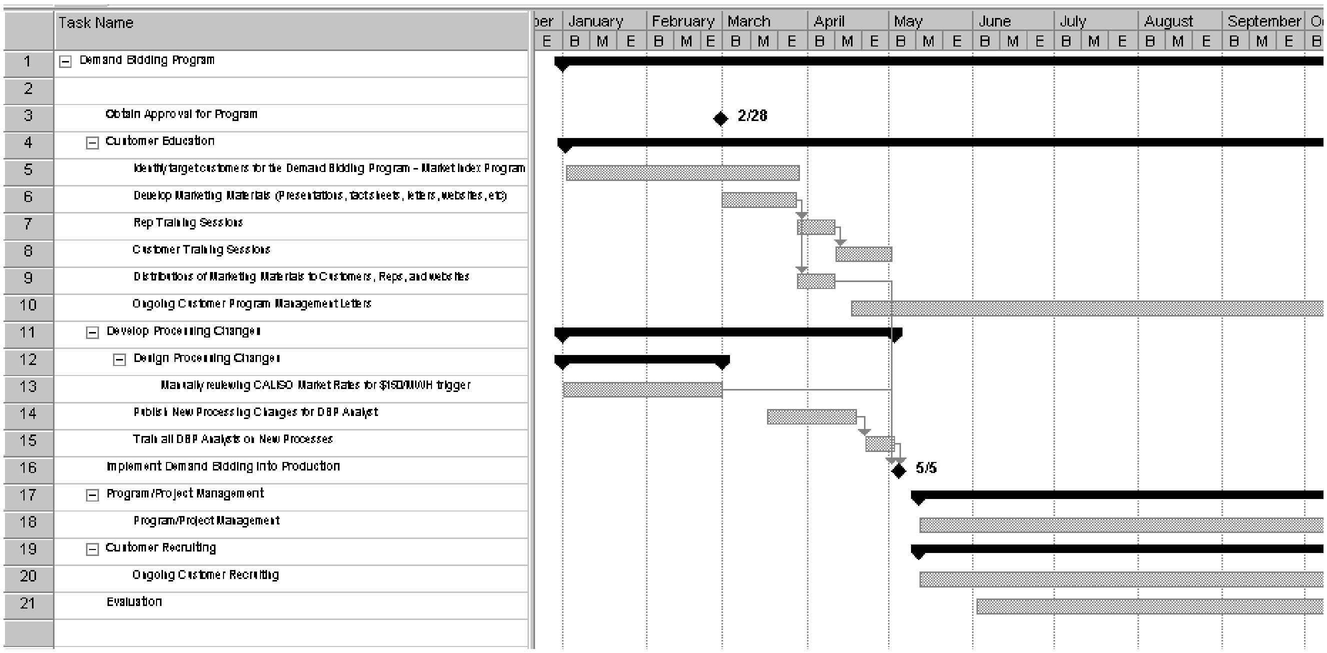
V.E. (9) PROPOSED METHOD OF IMPLEMENTATION

The key tasks to implement the modified DBP and the required time lines are presented in Table 2. A key task is customer education, which primarily involves the development of and distribution of new communications material, updating of websites and presentations/training to account representatives and existing and potential new DBP participants. In parallel with this task is the development or modification of existing processes, such as modifying manual billing spreadsheets, creating new customer tracking and reporting documents and training administrative staff in the new program. Once these two key tasks are completed the program will be ready for launch.

SCE will encourage its existing DBP customers to transfer to the new program. Additionally, account representative will endeavor to recruit additional customers after the program is launched.

At the conclusion of the first summer season, SCE will evaluate participant performance with respect to bidding levels, response to market prices, and compliance. SCE will also conduct a participant focus group in order to assess satisfaction with the features and operations of the program.

Table 10: Demand Bidding Program
Proposed Implementation Plan



V.E. (10) LEAD TIME FROM APPROVAL

From approval SCE expects to offer the program no later than June 1, 2003. Customer recruiting efforts will continue throughout the summer.

V.E. (11) OTHER IMPLEMENTATION ISSUES

None

Pacific Gas and Electric Company Specific Program Information

V.E. (4) INTENDED LEVEL OF PARTICIPATION

PG&E has 40 accounts participating in the current Demand Bidding Program. If all the accounts participate in the bidding event, this represents a minimum bidding demand of 6 MW and a maximum bid of 55 MW.

Under the proposed Demand Bidding Program, PG&E estimates the participation rate would increase to a total of 100 accounts representing an additional minimum bidding demand of 9 MW (15 MW total) and an additional maximum bid of 82 MW (137 total).

V.E. (5) SOURCES/LEVELS OF COST

PG&E anticipates that there will be costs in each of the categories identified below:

Metering

PG&E may incur some metering costs. There may be a few customers with maximum demands greater than 200 kW who will require additional metering. The estimated cost is $10,000.

Customer Billing

PG&E will incur costs to modify its billing system and to set up participating accounts for the demand bidding program. The estimated cost is $4,000.

Customer Operations/Notification System

PG&E will need to upgrade its existing software program to adopt the program's new triggers and to accommodate the revised settlement calculation for the program's operations. The estimated one time upgrade cost is $100,000. There will be continuing support for the operations/notification system as well as some manual processing on an ongoing basis. The annual cost is estimated at $50,000.

Customer Education and Recruiting

PG&E will need to create, print, and mail information regarding the Demand Bidding Program. PG&E's customer contact representatives will respond to customer inquiries regarding the program and assist customers in signing up for the program and obtaining internet access to the customer's meter data. The estimated one time cost is $50,000. PG&E will continue to market the Demand Bidding Program and answer customer inquiries regarding the program, triggered events, and incentive payments. The annual cost is estimated at $50,000.

Incentive Payments: There has not been a sufficient number of bidding events to determine the level of performance. It is therefore difficult to estimate future incentive payments.

V.E. (6) METHOD OF COST RECOVERY

To implement the demand bidding program, PG&E expects to incur incremental costs. PG&E proposes two components to the cost recovery mechanism for the demand bidding program.

First, PG&E proposes that a balancing account be established to track the incremental one-time "set-up" and on-going costs related to billing software/system modifications and customer education and recruitment. This approach will provide greater amount of flexibility as the final demand bidding program is finalized and implemented.

Second, changes in customer usage patterns could affect the quantity and/or types of procurement products or spot market purchases made on behalf of customers. For PG&E, the current Emergency Surcharge Balancing Account (ESBA) and the Transition Revenue Accounting (TRA) mechanisms record the actual costs of procurement products and spot market products. PG&E believes these risks should be explicitly considered.

Additionally, the current TRA mechanism ensures collection of authorized distribution, nuclear decommissioning, and public purpose program revenue requirements if changes in usage patterns from demand response programs results in an under collection of revenues. PG&E will seek similar accounting mechanisms once the TRA is no longer in place.

V.E. (7) LINKAGE TO PROCUREMENT ACTIVITIES

Some portion of the Demand Bidding Program's estimated MW demand response will be factored into the procurement portfolio. As PG&E gains experience in the performance of the Demand Bidding Program, the number will be modified.

V.E. (8) ESTIMATED START DATE

PG&E expects to implement the proposed Demand Bidding Program on June 1, 2003, provided CPUC approval of the program is issued prior to April 1, 2003.

V.E. (9) PROPOSED METHOD OF IMPLEMENTATION

Customer Education and Recruitment (2 months to complete)

The following tasks will be performed as soon as the CPUC issues a decision on the Demand Bidding Program:

- develop list of target accounts
- develop customer education and marketing material
- provide training to customer contact representatives

- send out education and marketing material to target accounts: customers on existing demand bidding program and customers who are not on the program

Customer signup will include:
- customer sign Demand Bidding Program agreement
- install any required metering equipment
- assist customer in obtaining internet access to their meter data

<u>Billing Software/System Modification (2 months to complete)</u>

Billing software/system modifications will begin as soon as the CPUC issues a decision on the Demand Bidding Program.

V.E. (10) LEAD TIME FROM APPROVAL

PG&E will need a minimum of 2 months to implement the proposed Demand Bidding Program.

V.E. (11) OTHER IMPLEMENTATION ISSUES

None at this time.

San Diego Gas & Electric Specific Program Information

V.E. (4) INTENDED LEVEL OF PARTICIPATION

SDG&E has 16 accounts with a pledged load reduction of 5.1 MW participating in the existing Demand Bidding Program ("DBP").

Under the proposed DBP, SDG&E estimates the participation rate would increase to a total of 25 accounts representing an additional 3 MW of pledged load reduction. Total estimated pledged load reduction is 8 MW.

V.E. (5) SOURCES/LEVELS OF COST

The DBP is an existing program with essentially all the infrastructure and processes in place. The primary proposed change to the program is the addition of a price trigger. Incremental costs to modify the existing demand bidding system is estimated at $7,500.

Due to the relatively small participation level, SDG&E currently calculates customer incentives for DBP manually. SDG&E does not anticipate incurring additional incremental costs related to billing system changes for the modified DBP. If participation levels exceed 25 accounts, SDG&E may need to reevaluate existing billing processes.

SDG&E expects to revise the existing DBP customer information package and collateral. Existing customer training material will also need to be modified. Incremental costs associated with modifying customer informational material is estimated at $7,500.

Incentive Payments: The existing DBP has not been initiated. Therefore, it is difficult to estimate future incentive payments at this time.

V.E. (6) METHOD OF COST RECOVERY

Operations & Maintenance (O&M)

SDG&E proposes to recover incremental O&M costs for DBP through its existing Interruptible Load and Rotating Outage Programs Memorandum Account (ILROPMA) until its next General Rate Case Filing, as directed in D. 02-04-060 (p. 18).

Incentive Payments

SDG&E proposes to recover incentive payments through the new Energy Resource Recover Account (ERRA) as described in the recent CPUC decision on Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development (D. 02-10-062).

Revenue Shortfall

SDG&E proposes to recover any shortfall in distribution revenues as a result of implementing DBP in the ERRA, as described in D. 02-10-062.

V.E. (7) LINKAGE TO PROCUREMENT ACTIVITIES

SDG&E plans to utilize demand response programs in its procurement activities. The amount of demand response for this and other demand response programs is uncertain at this time. As more experience with implementing demand response programs is gained, SDG&E will assess the levels of available demand response in its procurement portfolio.

V.E. (8) ESTIMATED START DATE

SDG&E expects to have the proposed Demand Bidding Program fully operational by June 1, 2003, provided CPUC approval is issued by April 1, 2003.

V.E. (9) PROPOSED METHOD OF IMPLEMENTATION

To ensure the modified Demand Bidding Program is fully operational by summer 2003, SDG&E will need sufficient time to educate, market and recruit customers. Concurrent with customer education and recruitment will be modifying the existing demand bidding software system. SDG&E expects customer education and recruitment and system modifications to take about two (2) months to complete. In addition, SDG&E would like to conduct system testing prior to June 1, 2003 to ensure communications and systems are operating appropriately.

SDG&E will encourage its existing DBP customers to transfer to the new Demand Bidding Program. Customer contact personnel will also strive to recruit additional customers after the program is launched.

V.E. (10) LEAD TIME FROM APPROVAL

SDG&E will need a minimum of 2 months to modify its existing system and effectively educate, market and recruit customers for participation in the proposed Demand Bidding Program.

V.E. (11) OTHER IMPLEMENTATION ISSUES

None at this time.

V.E. (12) ALTERNATE PERSPECTIVES

BOMA perspective:

This program would determine the customer's load reduction through reliance on their corresponding usage for the 10 similar days prior to the demand reduction bid. It is fairly well known experientially, as well as being corroborated by available research (such as that commissioned by the CEC and conducted by Xenergy, Inc.), that this baseline methodology often provides a relatively poor measure of the actual load reduction achieved by a customer in response to a triggering event. This is particularly true in the case of loads that are significantly weather- and temperature-sensitive, such as office buildings, which can be penalized significantly using this methodology.

The essential reason for this is that curtailment events often occur during warmer weather (when space cooling loads increase) whereas the days comprising the baseline, since by definition they are not program-call days, tend to be cooler days (when space cooling load is less). Therefore, in order for an office building to perform adequately under this proposed program design it must achieve two load reductions: the first to compensate for the higher temperature of the call day relative to the non-call baseline days; and the second to achieve a reduction relative to the baseline. This extra level of required performance creates a strong disincentive to weather/temperature-sensitive loads and thus weakens the overall demand reduction potential of this proposed program.

This problem can be mitigated by inserting an appropriate temperature-adjustment factor into the baseline methodology. This would increase the program's attractiveness to temperature-sensitive loads.

V. F. CPA Demand Reserve Partnership

V. F. (1) GENERAL DESCRIPTION

The California Power Authority (CPA) is using load reduction by end users to provide Demand Reserves in the wholesale market. The Demand Reserves can be used in 2 ways:
Ancillary Services – as 10 minute response non-spinning reserves or 60 minute response replacement reserves in the ISO markets, and
Call Option – as energy supplied in the ISO Day Ahead, Hour Ahead or Supplementary Energy markets during high wholesale market price or critical demand times.

CPA contracts with Demand Reserve Providers to work with end users and be contractually responsible for delivering the load reduction when called. Demand reduction for individual end users is limited to 11 am to 7 pm, Monday to Friday for 24 hours per month or 150 hours per year.

CPA has signed a Participating Load Agreement with the ISO to abide by the ISO's rules for load reduction to be used as supply in the ISO wholesale markets.

Two different types of baselines are used to compute load reduction. First, for delivery into the ISO real-time market by participating in the Ancillary Services or Supplemental Energy markets, the baseline is the ISO prescribed baseline – the load level in the interval (10 minute for non-spin and 60 minute for replacement and supplemental) before notification. Second, for the Call Options delivered into the ISO Day Ahead or Hour Ahead markets, the baseline is a load shape computed from the previous 10 business days, but calibrated to the load level for the three hours before notification. Businesses with temperature-sensitive or dynamic load levels would prefer delivery into the Hour Ahead or real-time markets for a baseline calibrated to that day's usage.

The baseline for incremental energy usage under the ISO Decremental Credit option is discussed under "(5) Sources/Levels of Cost" below.

V. F. (2) ELIGIBILITY

Any end users (bundled service or direct access) of the Investor-Owned Utilities would be eligible to participate in this program. In addition, end users of cooperating load serving entities can also participate.

V. F. (3) SOURCE OF DRIVERS/TRIGGERS

The IOU who buys the reserves determines whether to use it as a Call Option or in the Ancillary Services market. If it is used as a Call Option, the procuring IOU will select the hours to dispatch the load reduction. Typically, with an $80/MWH strike price, the IOU would dispatch this only when the spot market price exceeds $80.

If the IOU schedules the Demand Reserves as Ancillary Services or Supplemental Energy with the ISO, then the ISO dispatches the Demand Reserves along with other resources based on the energy bid price. End users in the Ancillary Services market can request a contingency reserve status which means they will not be dispatched until all other economic resources have been dispatched.

V. F. (4) INTENDED LEVEL OF PARTICIPATION

CPA has had end users (or their direct agents) express a bona fide interest in providing 500 MW of load reduction in this program.

V. F. (5) SOURCES/LEVELS OF COST

The IOU contracts with CPA to provide the Demand Reserves directly (or currently indirectly through DWR) just like if it were buying peaking capacity. CPA in turn pays the Demand Reserve Provider who compensates the end user for the demand reduction.

CPA will pay the Demand Reserve Provider for demand reduction that can respond within:
10 minutes and qualify to participate in the non-spin Ancillary Services market, $51/kW-yr and $.08/kWh;
60 minutes as a Call Option is paid $36/kW-yr and $.08/kWh;
60 minutes to participate in the ISO supplemental energy market, whatever energy price is bid when selected by the ISO;

In addition, per end users request, the CPA proposes an augmentation in which the IOUs will pay for incremental consumption of bundled service end users on firm service:
$.02/kWh whenever the ISO decremental real-time price is less than or equal to $.03/kWh but greater than $.015, and
$.035/kWh whenever the ISO decremental real-time price is less than or equal to $.015/kWh.

Moreover, the IOUs will pay for incremental consumption of bundled service end users on *non-firm* service:
$.01/kWh whenever the ISO decremental real-time price is less than or equal to $.03/kWh but greater than $.015, and
$.025/kWh whenever the ISO decremental real-time price is less than or equal to $.015/kWh.

Incremental consumption is defined as:

(Actual consumption that hour)
minus
(Average consumption during that time period (e.g., peak, partial, off-peak) for the same billing month in 2002)

The credits reflect that the generation component (excluding surcharges) of the energy charge in the appropriate retail rates ranges from $.04-.07/kWh. When the ISO price is significantly lower than these prices, the IOU incremental costs are lower – these credits incent incremental usage to be directed to such hours.

To implement the Call Option and ISO Decremental Energy Credit, no substantial changes are anticipated in the IOU processes. However, to implement the Ancillary Services and Supplementary Energy markets, the IOUs will need to put such load on a separate ISO Resource ID. This will have cost consequences in the managing of meter data and settlements. CPA is working with the IOUs and ISO to identify the incremental costs of this capability, which will become increasingly important anyway in the new wholesale market structure, with the increased emphasis on Demand Response.

V. F. (6) METHOD OF COST RECOVERY

This is a commodity procurement cost for the IOU just like any other peaking capacity contract purchase. However, IOU incremental system change costs to handle loads on separate ISO Resource IDs is probably better recovered similar to the recovery of O&M costs for other Demand Response actions.

V. F. (7) LINKAGE TO PROCUREMENT ACTIVITIES

Per the PUC Procurement Decision (D02-10-062) and presumably refined in this Rulemaking, the IOU will include this in its procurement plans.

V. F. (8) ESTIMATED START DATE

This program is currently underway. It is expected to significantly ramp up in June 2003 after the February decision in this rulemaking.

V. F. (9) PROPOSED METHOD OF IMPLEMENTATION

This program will be implemented using the infrastructure of the CPA Demand Reserves Partnership.

V. F. (10) LEAD TIME FROM APPROVAL

No operational lead time is required since we will use the existing infrastructure. However, there can be several months lead time to help additional end users participate.

V. F. (11) OTHER IMPLEMENTATION ISSUES

The terms on which customers can participate simultaneously on this program and other dynamic pricing and demand response options without double counting benefit needs to be clarified. Refinements in the use of the CEC metering infrastructure will make this program work better.

V. F. (12) ALTERNATIVE PERSPECTIVES

PG&E Perspective on CPA DRP Proposal

PG&E has significant concerns about both the viability of the CPA DRP and also about any plans to unilaterally assign DRP contracts to the utilities. While the CPA discussion of its proposal that appears here does not directly address the contract assignment question, CPA's consultant has confirmed at WG2 meetings that CPA would prefer to assign the DRP contracts to the utilities after they are creditworthy. California law, as incorporated in the California Civil Code, expressly provides that a contract requires the parties' mutual consent. PG&E is willing to explore mutually beneficial arrangements with CPA or DWR for the future administration of the DRP, subject to commercially reasonable terms and conditions. However, PG&E is not willing to assume DWR or CPA contracts except on a mutually agreeable, voluntary basis.

Contract assignment aside questions aside, PG&E believes the DRP to be an unproven program with questionable enrollment levels. The CPA conceded in one of its DRP presentations at Working Group 2 meetings that the program has been tested a number of times without showing reliable load reductions. More recently, it has also reported that some customers participating the program either do not have suitable metering, or appropriate meter data access is unavailable, meaning that actual results for those DRP operations that were conducted this past summer (during July and August) are still not available for analysis, three and four months after the fact. Assigning responsibility for resolution of these issues to the utilities together with the contracts would pose significant additional administrative burdens and costs.

PG&E Perspective on CPA Incremental Load Incentive

PG&E addresses the CPA incremental load "augmentation" (as discussed under the last four paragraphs of Section V.F. (5)) as a separate proposal, because this proposal would apply under wholly different operating conditions than does the original CPA DRP program. All three of the utility real-time pricing variants do offer lower TOU or real-time prices under conditions similar to those where CPA's incremental load incentives would be activated. However, PG&E is concerns that, as with the ACWA CPP proposal, the CPA incremental load incentive has been formulated as a "no losers" rate offering. This means that significant dollar amounts could be paid out as incentives without having any corresponding load changes result from this proposal.

SCE Alternative Perspective

SCE agrees with the comments of PG&E on the CPA Demand Reserve Partnership proposal. In addition, SCE submits the following comments. CPA continues to present its existing program approved by the State last year as DR option to be considered in this proceeding. In the pending procurement OIR the UDC's take issue with the assignment of this contract. It is expected that this issue will be addressed in the on-going procurement OIR. Nevertheless, the UDC's continue to work with the CPA to address potential transition and/or implementation issues associated with considering this resource as a procurement option. To further this objective, the UDC's would request that CPA provide an updated assessment of the available load on the program that has passed ISO certification, historical performance results, forecast of additional participation by service area, and extent and length of DWR commitment to this contract.

CPA also proposes to incent purchases during time periods when the ISO posts a "decremental" price...SCE submits that much needs to learned about how this market operates, when decremental price information is available to customers, how often this situation is expected to occur in the future, and how to measure incremental/decremental load, before this option can be considered. Because two part pricing and customer baselines are critical to the success of this option, SCE would propose that this option be addressed along with resolution of issues associated with the two part pricing proposal."

V.G. Status on Development of a Two-Part RTP Tariff

As a result of the promising reports of two-part RTP tariffs at the experiential workshops held September 9-10, 2002 in this proceeding, WG2 was encouraged to develop a two-part tariff.[7] A Two-Part RTP tariff is one where a customer is billed one rate based on a baseline amount of usage, and is billed (or credited) a second rate for the difference between actual usage and their baseline usage. The two-part tariff is popular among regulatory agencies, and appears to be acceptable in some form to customer groups. Generally, utilities are somewhat skeptical of its workability, but are willing to work to resolve implementation issues. The consensus in WG2 seems to be that there are some hurdles to be overcome before implementation of a two-part tariff is possible, and therefore discussion of two-part RTP should be slightly delayed until after WG2 has finished finalizing their 'quick-win' tariff proposals.

The biggest issue to be resolved for implementation of a two part tariff is that of the baseline. Baselines can be assigned on the basis of a customer's historical usage, or could be individually negotiated. Additionally, baselines can be established once-and-for-all, or could be updated regularly. All the methods have their advantages and disadvantages. Using historical usage is simple, but a non-standard historical reference year can lead to a baseline set too low or too high. Individually negotiated baselines would be more fair and accurate, but are administratively burdensome and open the door to reasonableness, arbitrariness, consistency, and favoritism issues. Regular updates may be necessary to keep up with a customer's changes in usage pattern, size, and technology, but they are also time consuming, and in part could counteract the incentive to change consumption patterns in the first place. On the other hand, permanent baselines can become obsolete over time.

A second important issue is on recovery of non-generation costs for incremental usage above the baseline. If transmission and distribution (T&D) costs are recovered in part through volumetric rates, and fixed baselines result in fixed volumes for recovery of T&D costs, then incremental usage will impose T&D costs without paying those costs through rates. A potential solution is to base the T&D rates on the costs of total usage, but only recover those through baseline usage volumes. The T&D rates would be updated through the standard GRC process.

A third issue for two-part tariffs is the low volatility of current market prices. We assume that the second part of a two-part tariff will rely on wholesale market prices, which we understand to be relatively low and stable at this point in time. We are therefore concerned that these low and stable prices will not incent any demand response, and in fact may not even encourage or compensate participants for initial investments in demand response technology or techniques.

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[7] ALJ Ruling of October 2, 2002, pp. 3-4.

Finally, customer eligibility is an issue. There are two parts to the eligibility issue. If the chosen baseline methodology is historical, participants would naturally need a history in order to participate. There are indications that only customers with demand above 500 kW currently have a long enough history to serve as a satisfactory baseline. Additionally, one possibility for using history as a baseline is to restrict eligibility to those whose usage patterns are stable over time. If we set our stability requirements too strictly, we will end up with few participants. On the other hand, loose stability requirements will result in baselines that do not truly forecast or represent a customer's likely usage in any given hour.

Working Group Two intends to establish a sub-group to set a schedule for discussion and implementation. Such a schedule should not interfere with completion of the 'quick-win' tariff proposals. The following proposed schedule attaches the two-part RTP discussions to the back of the 'quick-win' process. The group agrees that the October 1 date for having the tariff in effect should be treated as firm, the intermediate dates should be treated as target dates, to be adjusted by the group as needed. As each phase of the 'quick-win' proposal implementation is finished, a similar phase should begin for two-part RTP. At the end, there would be a four month period between the implementation of the 'quick-win' proposals and a two-part RTP proposal.

Table 11: Two-Part RTP Tariff Proposed Schedule for Development and Implementation

Date	Quick Win	Two-Part RTP
9/02 - 1/03	Development of Tariffs	
12/15/02	Report to WG 1	
12/15/02 - 4/15/03		Two-Part RTP Workshops
2/1/03	Final Decision	
2/03 - 6/03	Marketing of Programs	
4/15/03		Recommended Tariff to WG 1
6/1/03	Tariffs in Effect	Final Decision
6/03 - 10/03		Marketing of Program
10/1/03		Tariff in Effect

The advantages of this schedule are that 1) the teams working on the various phases of implementation of the tariffs will not be working on both the 'quick-win' and two-part RTP at the same time, and 2) by the time the two-part tariff is ready, it can be marketed for introduction at a time most beneficial and least risky for participants, which is winter.

VI. GENERIC IMPLEMENTATION ISSUES

Section VI raises various generic implementation issues that are common to one or more of the proposed tariffs and programs. Such issues are classified into three groups: (1) concerns about recovery of costs associated with program development, ongoing implementation, marketing, and customer education, and (2) other non-specific issues.

VI.A. Cost Recovery

VI.A. (1) INTRODUCTION AND OVERVIEW

The Ruling Following Prehearing Conference, dated August 1, 2002, lists eight Responsibilities for Working Group ("WG") 1, one of which was to "review and assess implementation issues raised by the Working Groups (e.g., meter ownership; financing and revenue requirements concerns)."[8] Even though there were limited discussions on precise implementation issues related to cost recovery in WG 2 meetings, basic assumptions were addressed and proposals were made by the IOU's and other parties.

Assigned Commissioner's and Administrative Law Judge's Ruling Following the Third Meeting of Working Group 1 ("Ruling"), dated November 13, 2002, among other things, provided specific guidance on cost recovery for WG 2 and WG 3. Given the recent availability of WG 1 guidance on cost recovery, this section of the report partially but not fully complies with the requirements as set forth in the Ruling. This Report provides an overview and comparison of the different cost recovery proposals from the IOUs and other parties. Per the Ruling, WG 2 will continue to work toward "an explicit cost recovery mechanism[s]" for funding demand response tariffs and programs, and will expand on cost recovery mechanisms in its second Report filed on December 13, 2002.

On November 5, 2002, the three IOUs and other parties in the WG 2 submitted demand response program proposals for large customers, which addressed cost recovery issues. The IOUs included a Joint Utility Demand Bidding Program ("DBP") proposal with IOU-specific cost recovery mechanisms. There was a consensus in WG 2 that recovery of the revenue shortfall resulting from demand response programs offered to their bundled service customers[9] should be recovered from all customers through existing balancing accounts (in some cases, balancing accounts were proposed to be used to recover procurement costs as well). There were different proposals for cost recovery mechanisms, but

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[8] Ruling Following Prehearing Conference, p. 3.

[9] Except for PG&E, which it did not explicitly identify, revenue shortfalls associated with its proposed DBP.

all proposals are intended to track and recover incremental Operations and Maintenance ("O&M"), capital, and incentive payments through either a balancing account[10], or memorandum account [11]. Table No. VI.A.1 summarizes the specific cost recovery proposals by the IOUs and other parties.

VI.A. (2) SUMMARY OF IOU'S AND OTHER PARTIES COST RECOVERY PROPOSALS

PG&E Proposal

PG&E proposes a Joint Utility DBP and an RTP/CPP tariff for its large customers. PG&E anticipates incurring costs associated with metering, O&M (including billing and billing system modifications), program marketing, customer education, and administrative costs. In Sections V.C. and V.E. PG&E proposes to establish a new balancing account to track the one-time and on-going incremental O&M costs, e.g., data collection for billing, billing system modifications, and customer education and recruitment. PG&E did not propose to separately track revenue shortfalls associated with its two proposed programs since any such shortfalls would be captured in existing ratemaking mechanisms described below. However, PG&E believes the Commission should consider the revenue shortfall risks resulting from the changes in rates and demand when making its selection on which programs should be implemented. Currently, PG&E has two existing accounting mechanisms: Emergency Surcharge Balancing Account ("ESBA") and the Transition Revenue Account ("TRA") to record the actual procurement costs and revenues. The TRA records revenues and authorized costs for non-procurement items as well. PG&E will seek similar accounting mechanisms once the TRA is no longer in place in order to ensure the recovery of the authorized functional revenue requirements, e.g., distribution, nuclear decommissioning ("ND"), and public purpose programs ("PPP"). In Section V.A. (5), PG&E provided its estimated level of costs associated with its proposed DBP and RTP/CPP.

SCE Proposal

As shown in Section V.B and V.E, SCE proposes two demand response programs for its large customers with demand over 200 kW: 1) Joint Utility Demand Bidding Program ("DBP"), and 2) Real-Time Pricing – Market Index ("RTP-MI"). Both programs have costs associated with O&M, revenue shortfalls, program marketing and customer education. In addition, the DBP has costs associated with the incentive payments, which are currently recorded in the existing Interruptible Program Memo Account ("ILPMA"). Many of the O&M expenses, e.g., billing and billing system modification and marketing costs, are currently either recorded in the ILPMA or included in current rates. For future recovery purposes, SCE proposes to establish a new balancing account to track

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[10] PG&E and SDG&E.

[11] SCE and supported by ORA.

the incremental O&M expenses for each of the cost sources rather than to record such costs in ILPMA. SCE anticipates minimal capital costs for both programs but proposes to record any revenue requirements related to the capitalization of costs in a proposed balancing account for future recovery.

SCE provides each of the costs sources/estimated levels and proposed recovery for both programs. For revenue shortfalls, SCE proposes recovery through its existing ERAM-like balancing accounts for distribution and generation revenues. SCE points out that significant revenue shortfalls from the DBP could potentially delay the recovery of the PROACT balance, and therefore extend the Settlement period. SCE proposes to track the revenue shortfalls in a new balancing account, which should allow the Commission to determine the significance of the revenue shortfalls, and to make the appropriate ratemaking adjustments.

SDG&E's Proposal

SDG&E proposes to convert its Hourly Pricing Option Tariff ("HPO") from a pilot to full production. In Section V.A. (5) & (6), SDG&E provides the sources and its estimated level of costs and proposed cost recovery. Similar to PG&E & SCE, SDG&E proposes to track revenue shortfalls from the HPO in its new balancing account established by D.02-10-062 and recovery through future energy rates charged to all bundled customers. In addition, SDG&E proposed to establish a new balancing account to track incremental O&M costs not covered in rates and requests recovery in either its next GRC or cost of service filing, or the next AEAP filing. SDG&E proposed to recover its capitalized costs, e.g., metering through its distribution rates for all customers as plant additions in rate base.

CPA Proposal

CPA proposes a demand bidding program for bundled and direct access customers called "Demand Reserve Partnership" which is based on its current demand bidding program, which is available to direct access customers. In Section V.F (5) & (6), CPA provides the sources and levels of the program costs. The main cost of this program is the contract/incentive payments to the Demand Reserve Providers who compensate the end user for the demand reduction. In addition, CPA proposes per end users request, that the IOUs will pay a contracted price[12] for the incremental consumption of bundled service for end users on firm and non-firm services whenever the ISO decremental real-time price is within a certain range. CPA proposes that the IOUs to recover these costs including contract incentives and incremental energy consumption costs as the commodity procurement costs. Based on operating experience to date, no material IOU operating costs are expected to support end users participating on the Call Option. However, for bundled service end users participating in the ISO supplementary energy and Ancillary Services markets, the IOUs will incur

[12] $0.035/kWh - 0.02/kWh for firm and $0.025/kWh - $0.01/kwh for non-firm services.

incremental costs for managing meter data and handling ISO settlements. CPA is working with the IOUs to define these incremental costs by the December 13 report. They will probably be recovered using the same mechanism used to recover the other O&M related Demand Response costs incurred by the IOUs. For revenue shortfalls resulting from bundled and direct access demand responses, CPA proposes the same balancing account mechanisms as proposed by the IOUs.

VI.A.(3) DISCUSSIONS

As summarized above, there was a consensus in WG 2 that recovery of the revenue shortfalls[13] should come from bundled customers to the extent that such programs benefit only bundled service customers. Any cost recovery mechanism should include tracking with some kind of reasonableness review. It should be noted that the Phase II decision (D.02-04-060) in the interruptible proceeding specified a maximum demand reduction of 5 percent (or 2,500 MW), thus reducing the total annual interruptible program budget to $250 million for the three IOUs. ORA requests WG 1 to indicate whether a similar limit for demand response and program costs is appropriate for this proceeding.

PG&E, SCE and SDG&E propose balancing accounts rather than memorandum accounts. Both memorandum and balancing accounts provide regulatory assurance of cost recovery, with the main difference being the reasonableness review process. A balancing account mechanism provides the IOUs with a more immediate opportunity to record and recover demand response program costs in rates. Alternatively, a memorandum account tracks costs for future recovery.

In its cost recovery proposal, SCE indicated only two types of revenue shortfalls: 1) distribution and 2) generation. As pointed out in PG&E's proposal, demand reduction from the proposed demand response programs will potentially result in revenue shortfalls not only in distribution and generation, but also in other functional rates, e.g., transmission, public purpose programs ("PPP"), and nuclear decommissioning. The revenue shortfall from a full production program may be significantly different when compared to pilot programs. The Ruling also recognizes the potential revenue shortfalls.

The IOUs' proposed balancing account treatment meets the WG 2's objective of providing the IOUs with full cost recovery, but may not necessarily track all the revenue shortfalls by class or tariff. That is because these accounts do not necessarily distinguish revenues from costs by class or tariff. In the next phase of WG 2, additional work will be done to determine which costs and, potentially, which revenues, should be tracked in order to evaluate the programs ultimately adopted.

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[13] Except for PG&E, which it did not explicitly identify, revenue shortfalls associated with its proposed DBP.

ORA's Alternative View Point

ORA prefers the memorandum account recovery mechanism, which appears to be consistent with the Commission's existing policy towards interruptible and demand response programs.

VI.A. (4) CONCLUSION

While WG 2 has reached consensus that cost recovery is appropriate and necessary, there are still differing opinions on the best approach to ensure cost recovery. WG 2 will continue to work toward "an explicit cost recovery mechanism" for funding demand response tariffs and programs, and will expand on those cost recovery proposed mechanisms in its second Report filed on December 13, 2002.

VI.B. Other Non-Specific Issues

This subsection discusses various other generic issues that cut across one or more specific proposals.

VI.B.(1) AVAILABILITY OF CAISO MARKET PRICES

Development of market price-based tariffs would be greatly aided by the implementation of a Day Ahead market for spot purchases, such as the now-defunct California Power Exchange, that provides a liquid and transparent basis for describing market prices. The existing trade press description of volumes and prices for bilateral trades are based on voluntary reporting, and there is little understanding of the degree of coverage and accuracy for these activities.

In its market Design 2002 (MD02) proposals, the CAISO proposed to create a Day Ahead hourly market for energy by eliminating the market separation rule and the balanced schedule rule and integrating A/S procurement with congestion management. This would effectively create, and respond to FERC direction to facilitate, a Day Ahead hourly market for spot energy. CAISO proposed that its Day Ahead market be implemented April 2003. In its order of July 17, 2002 addressing MD02 proposals, FERC approved formation of a Day Ahead market, but directed it be implemented at the beginning of 2003. Subsequently there have been various filings from the CAISO and orders from FERC seeking to clarify the scope of MD02 changes and implementation dates. In particular, on November 8 the CAISO filed an Emergency Request for Rehearing and Motion for Clarification regarding FERC's October 11 Order regarding the CAISO's previous request for rehearing and compliance filing. The CAISO's request for rehearing details several reasons why it is impossible to implement any type of forward energy market in early 2003, and that attempting to implement even a simplified energy market prior to the CAISO's proposed integrated energy, ancillary service, and congestion management market would probably result in delaying the integrated market beyond the Fall of 2003. At this time, FERC has not authorized the necessary details for implementing a forward energy market, and at the CAISO's request, FERC has scheduled a Technical Conference for December 9 regarding the unresolved elements of the CAISO's market design."

The uncertainty of the start date for a Day Ahead market and lack of knowledge of its performance make proponents of tariffs and programs hesitant to commit themselves to use of CAISO Day Ahead prices, even though most support shifts to this source of market prices when its characteristics are better known and it has been judged to be an accurate and transparent source of market information.

An additional element of ambiguity exists about both Day Ahead and A/S market prices because the FERC orders establish a soft cap of $250 per MWh. A soft cap implies that bidders into these markets can submit bids that exceed $250 per MWh, and the ISO can accept such bids if required to assure reliable system operation, but bids above $250 per MWh do not set the market clearing price. This suggests that dynamic tariffs and load bidding programs using the official market clearing price might not actually communicate the costs of the incremental supply source if the CAISO accepts bids greater than $250 per MWh. Further discussions with the CAISO are required to understand how the volume and costs of bids accepted above the soft price cap can be used as the basis for providing equal opportunities for demand response and minimizing the total costs of procuring resources to satisfy customer loads.

The prospect of shifting to CAISO Day Ahead prices as a “driver” for market-based tariffs and load bidding programs suggests that one or both of the following options should be considered:

> a. describe the market-based price driver in very general terms and allow UDCs the flexibility to shift from one source to another as they find more accurate descriptions of incremental market prices, and
>
> b. approve tariffs and programs with clearly specified price sources, and require UDCs to file advice Letters each time they propose to shift from one driver to another.

The former option provides greater flexibility to the UDC, but creates greater uncertainty about price patterns, perhaps causing customers to defer signups. The latter option requires greater administrative effort by the UDC, Commission and various parties participating in the advice letter review process, and may cause customer drop out at the points when a shift between price drivers is made.

VII. RECOMMENDATIONS

WG2 makes a series of recommendations to WG1 for programs to be implemented in 2003 based on the work to date, classified into two categories: (1) program/tariff design, and (2) implementation. Recommendations concerning monitoring and evaluation/adjustment will be submitted as part of the December 13, 2002 report.

VII.A Tariff/Program Design

1. Three specific tariff design objectives should be adopted to increase customer acceptance and response to dynamic pricing tariffs: (a) simplicity, (b) stability, and (c) readily discernable customer risk (recognizing that less risk means less opportunity for bill savings by customers).

2. All dynamic pricing tariffs should be voluntary.

3. To satisfy a wide range of customer needs, and to obtain a range of experience, the Commission should adopt tariffs/program for 2003 reflecting all three types of programs proposed in this report, namely hourly pricing, critical peak pricing, and demand bidding.

4. WG2 shall continue to work toward development of a two-part RTP tariff and other forms of CPP to address key conceptual design, implementation and marketing issues that need to be resolved prior to adoption. WG2 shall submit a progress report to WG1 by April 15, 2003 as part of a commitment to have a two-part RTP tariff ready to be implemented on October 1, 2003.

VII.B Implementation

1. IOU's shall be assured full cost recovery for all tariffs/programs approved in this proceeding.

2. To obtain confidence and predictability in customer demand response and to achieve consistency with the goal of program stability, the Commission should direct UDCs to each year dispatch all dynamic pricing tariffs/programs at a level necessary to assure continuing performance.

Appendix A. List of Primary Authors

Report Section/Subsection	Author	Organization
Executive Summary	B. Kaneshiro	CPUC
I. Introduction		
A. Mission for >200 kW Customers	C. King/M. Jaske/B. Kaneshiro	eMeter/CEC/CPUC
B. Nature of the WG Process	“ “	“ “
C. Role of this Report	“ “	“ “
II. Experience with Dynamic Tariffs/Programs		
A. In California	A. Bell	PG&E
B. Outside California	C. King	eMeter
III. Fundamental Considerations		
A. Economics vs. Reliability	C. Blunt	ORA
B. Revenue Neutrality	C. Blunt/M. Jaske	ORA/CEC
C. Voluntary vs. Mandatory	C. Blunt	ORA
D. Customer Interest	B. Barkovich/K. Lindh	CLECA/CMTA
E. Direct Access Issues	B. Barkovich/G. Lizak	CLECA/IM Serv
IV. Screening Process		
A. Rationale for Criteria	D. Hungerford/M. Jaske	CEC
B. Results of Screening Process	D. Hungerford/M. Jaske	CEC
V. Specific Proposals		
A. Hourly Pricing Option	P. Borkovich	SDG&E
B. RTP – Market Index	L. Low	SCE
C. Summer CPP	A. Bell	PG&E
D. CPP	L. House	ACWA
E. Revised Demand Bidding	L. Low/E. Wong/S. Sides	SCE/PG&E/SDG&E
F. Demand Reserves	J. Flory	CPA
G. Two-Part RTP Status	C. Blunt	ORA
VI. Generic Implementation Issues		
A. Cost Recovery	C. Blunt	ORA
B. Other Non-Specific Issue	M. Jaske	CEC
VII. Recommendations	WG 2 Participants	
APPENDICES		
A. List of Authors	B. Kaneshiro	CPUC
B. Meeting Minutes	B. Kaneshiro/M. Jaske/D. Hungerford	CPUC/CEC
C. Matrix of Instate/Out-of-State Tariffs and Programs	C. King	eMeter
D. Details of Screening Process	D. Hungerford	CEC
E. PG&E’s CPP Rate Design & Example Customer Bill Analysis	A. Bell	PG&E

Working Group 2
September 18, 2002 Meeting Minutes

I. Organizational Issues

Discussion focused on a handout from Mike Jaske called "Proposed Practices for Working Group 2". Topics included how the Working Group meetings will be run, what is expected from the participants, and other administrative details. One important area of clarification: the final Working Group 2 report will be a collaborative effort involving contributions from the participants, and that differences of opinion will be reflected in the report if any exist.

II. Review of Assigned Objectives for the Working Group

Develop at least one dynamic tariff.

Discussion focused on following preliminary considerations:

Whether WG 2 should consider programs in addition to tariffs. There was a distinction made that a tariff is more of a pricing scheme built into rates, whereas a program can offer incentives such as rate discounts. There was a general agreement that consideration of programs in addition to tariffs was appropriate, but that it was important to ensure that WG 2 uses the limited amount of time to develop at least one tariff or program well, as opposed to developing several choices ineffectively. Many parties emphasized that although comparing tariff proposals to programs was appropriate, the comparison should not be as in depth as the analysis of the tariff proposals. Parties were also asked to bring forward those programs they felt should be used in those comparisons. One clarification: the expectation is that WG 2 will produce three tariffs (or programs), one for each IOU (there may be subtle differences amongst the IOU tariffs).

Consideration of Mandatory vs. Voluntary. WG 2 affirmed that this issue would be part of the tariff assessment in future meeting(s).

Clarification of what an Implementation Plan would include. In general the Plan should include everything that is necessary for the tariff to become reality. WG 2 identified the following areas as key elements: regulatory process, financing issues such as revenue recovery and cost allocation, infrastructure needs, marketing and customer education requirements, and IOU billing requirements (one participant disagreed that IOU billing requirements is a relevant item for implementation considerations). The IOUs will be asked to develop a comprehensive outline of an Implementation Plan at a later date.

Interaction with Existing Programs: There was general agreement that the assessment of a new demand response tariff or program will need to be made within the context of existing demand response programs. Adding on another 'layer' of programs has several implications such as revenue recovery, customer receptivity, and effectiveness. A key part of assessing a new program in the context of existing ones is to determine what is the "macro" goal beforehand so that all the programs fit together harmoniously.

Schedule of Deliverables: There was general agreement that it would be more manageable for WG 2 to produce its work products into two separate pieces: the tariff(s) and implementation plan (Agenda items II.A.1 and 2) would be an initial work product, and the assessment, cost-effectiveness and estimated range of response (Agenda items II.A.3 and 4) would be developed later.

Identify existing pilots that could be improved

A proposal was made to expand this objective to consideration of new, additional pilots that could be implemented (rather than being restricted to modifying existing pilots). No strong opinions on this proposal were apparent.

Identify additional tasks for Phase 2 of the proceeding

This objective was not discussed.

Direct Access issues

Discussion focused on potential equity issues for direct access customers as many of these customers have paid for their own interval meter. Some participants expressed concern that financing of demand response programs through T&D rates would be an issue for direct access customers. As directed in the September 5 ruling, WG 2 is expected to report on implications for Direct Access customers.

Duel-fuel metering and communication issue

There was a general consensus that this issue is not relevant for WG 2, but would be a more appropriate topic for WG 3 to tackle.

Analysis Requirements to Produce the Proposed Tariff(s) and Assessments

Identify and Evaluate Candidate Designs

The following programs were agreed upon potential candidate programs: a.) RTP proposals made by the IOUs and the CEC to the CPUC in August 2001, b.) Critical Peak Pricing and c.) Demand Bidding (the original design).

Select Short List and Develop Complete Proposals

The following screening criteria were agreed upon, and will be used as part of a preliminary evaluation of the candidate proposals on September 25:

Tariff in place by Spring '03
Achieve significant demand response
Customer acceptance (significant amount of sign-ups)
No significant opposition
Ease of understanding for customers
Interaction with existing programs
Cost of implementation
Coordination of demand response to achieve system benefits

Conduct Assessments

The discussion of WG 2 focused on four key components anticipated for the assessment of the candidate tariffs: a.) Revenue Neutrality, b.) Cost-Benefit analysis c.) Risk Assessment and d.) Feedback from potential customers

- Revenue Neutrality: the issue is complex but appears to be centered on two sub-topics: class revenue neutrality and designing rates to reflect actual costs (which would affect overall system revenue neutrality). Revenue neutrality for either sub-topic is difficult to discuss without specific proposals since any analysis is based on assumptions made about various inputs such as load shape changes. WG 2 agreed that when the candidate tariffs are discussed at the Sept. 25 meeting, the IOUs would need to also address the revenue neutrality issues including information about assumptions made and the magnitude of effect. In addition, it would be helpful for one entity to do a 'primer' on revenue neutrality so that WG 2 is operating on the same definitions.

- Cost-Benefit Analysis: A discussion emerged concerning the practicality of a cost-benefit analysis assuming that WG 2 is producing a pilot program. Typically pilot programs are used to generate data to support an ex ante cost-effectiveness analysis for a scaled up program; pilot programs themselves are not usually expected to be cost-effective. This may be an issue to kickback to the Policy Working Group for clarification. If a determination is made to do a cost-benefit analysis ex-ante, there was general agreement that the Standard Practice Manual is a good starting to point in developing a framework. There are three key inputs to the SPM methodology:

- Benefits to Quantify or "Value of Response"
  - Marginal capacity cost
  - Price suppression
  - Marginal energy costs
- Anticipated Demand Response (# of MWs that can be obtained)
- Implementation Costs

There was general agreement that the Policy Working Group should be asked to provide specific input concerning Benefits to Quantify, while WG 2 could develop the other two input areas.

Regarding predicting customer demand response, the following components were identified: i) # of customers on the program/tariff, ii) price differential (between off-peak and on-peak or between current rate and new rate), iii) degree of investment on the customer side, and iv) % of energy costs as part of the customer's total operating costs.

Regarding implementation costs, WG 2 discussed ideas concerning marketing and customer education in terms of appropriate levels and how those costs would be allocated. No specific consensus emerged. IOUs could address as part of their implementation plans.

- Risk Assessment: The discussion focused on the necessity of risk protection or hedging in the programs. Some participants mentioned that many customers would feel uncomfortable with programs that have zero protections from price volatility. Some participants felt that risk protections run counter to the objective of demand response program. Others mentioned that price protection products could be provided by third-parties. No significant consensus emerged on this issue.

- Feedback from Potential Customers: WG 2 agreed that a cross-section of large customers should be enfolded into the assessment process so that the programs will be designed to attract participation. WG 2 agreed that a two-step process would be the best approach where early feedback could be obtained on the initial program design and principles, and provided again at a later stage, when large customers could be provide specific rate effects.

III. Analysis to Produce Pilot Recommendations

WG 2 did not discuss this topic.

IV. Brief Review of Production Process for the Working Group Report

WG 2 did not discuss this topic in detail other than what was clarified in Section I.

V. Wrapup and Review

WG 2 agreed the following deliverables would be discussed at the next WG 2 meeting on September 25:

- Candidate Programs/Tariffs provided by:
  - RTP proposals: IOUs and the CEC (4)
  - Critical Peak Pricing proposal: Karen Herter
  - Demand Bidding proposal: John Molinda

  The proposals (1- 2 pages) should include a summary of basic design features. In addition the IOUs would provide revenue neutrality information for their proposals.

- Screening Criteria: all participants may provide precise definitions of the screening criteria agreed upon, such as rephrasing the criteria into a question, or developing a numeric measurement. Participants may also suggest additional criteria for WG 2 to consider.

- Revenue Neutrality 'primer': ORA will provide a basic explanation of definitions and concepts intended to help all participants.

- Cost-Benefit Analysis: King and Anderson will provide a first step proposal using the Standard Practices Manual as a framework.

- Experiential Workshop Data: David Hungerford (CEC) will provide a summary of the Experiential Workshop (Sept. 9 and 10) presentations.

- Representatives of the large customer groups (CMTA, water agencies, state agencies) will organize a cross-section of large customers to attend the September 25 meeting so that feedback can be provided on program design.

- Outline of the Working Group 2 Report: SCE will provide a proposed outline.

- All those responsible for deliverables should circulate their materials via email in advance of the Sept. 25 meeting, preferably 24 hours in advance.

Working Group 2
September 25, 2002 Meeting Minutes

Getting Oriented

Introductions and administrative items discussed. Jaske expressed the belief that the assignment to Working Group 2 is to develop a "production tariff" that would achieve substantive demand response, not just pilots that explore customer response to various hypothetical designs.

Review of Standard Practice Tests and Key Assumptions (Item V. on the agenda moved up to beginning of the meeting)

King and Anderson made a presentation on benefit-cost analysis using the Standard Practice Manual as a framework. The presentation provided details concerning the four standard practice 'tests' that are done and the key drivers of the analysis. One point of discussion was whether it was 'double-counting' to include capacity costs and the outage costs. Presenters identified the "cost of capital" as a big unknown in determining the cost of a peaker. The presenters felt that use of the SPM as a cost-benefit analysis for demand response programs is possible. There remains an outstanding question as to how 'deep' to go with any cost-benefit analysis for WG 2 products. Part of the answer to that question is dependent on the WG 2 objective: pilots or full rollouts. (If pilots are the emphasis, then a full cost-benefit analysis is not necessary since the idea is to learn from the pilot(s).) Since the nature of Working Group 2 assignments and schedules is unclear, Working Group 2 did not attempt to define key inputs for an SPM analysis of demand response programs.

VI. Review of Proposed Screening Criteria

Working Group 2 discussed the draft matrix provided by Jaske, which outlined a proposed set of screening criteria for the tariff proposals that were discussed on September 18. The matrix included five general areas of criteria (policy, customer choice, DR potential, equity, and costs) and also included specific measurement indicators and outcome goals. Some additional measurement indicators suggested by the group included: implementation issues, measurement/verification of customer reductions, duration/commitment of the program, scalability of implementation costs, interface with existing programs, and environmental impacts.

The comments from the discussion were considered during the lunch hour to modify the matrix, which was shared again with Working Group 2. Further modifications were made until the WG was satisfied with the criteria for use in screening proposed programs.

VII. Candidate Dynamic Tariffs/Programs

A total of 9 tariffs/programs were presented. The presenters also did a quick review of their proposals in light of the revised screening criteria matrix (the post-lunch version).

- SDG&E made a presentation on its pilot Hourly Pricing Tariff (HPO). In the absence of an actual daily Ahead market houring price, SDG&E creates a synthetic price based on the cost of daily energy and revenue requirement. Discussion focused on tariff's price floors and ceilings, and that undercollections for this tariff are resolved using a balancing account spread to all customers. SDG&E is just about ready to solicit customer participation, which is limited to 35 customers.
- O'Sheasy made a presentation on the two-part RTP tariff, based on the experience from Georgia Power's RTP program. Much of the discussion focused on the Customer's Baseline Load (CBL), a historical load shape for each customer in the program. O'Sheasy stated that the CBL was a key to assuring revenue neutrality. The CBL is key in terms of getting demand response, but also in determining revenue recovery for the utility. Thus, the methodology for establishing it is a key detail. There was concern expressed as to whether CBLs could work in California given weather-sensitivity for potential participants and other concerns as to the validity of CBLs over time. There is also the concern of having a permanent customer CBL.
- SCE presented a proposal based on the RTP-2 tariff, which is currently in existence (85 customers on it) This is a tariff that features ex ante hourly price patterns based on forecasted daily temperature. SCE is willing to consider shifting this tariff's trigger to market prices.
- SCE also presented a second RTP tariff, currently closed due to the collapse of the Power Exchange, which used the PX unconstrained market clearing price as the source of RTP values
- SCE also presented a proposal to modify the existing Demand Bidding Program (DBP) by including a price trigger in addition to the program's reliability trigger. Discussion of the scope of this proceeding and its latitude to propose yet further changes to this oft-changed program were not resolved.
- PG&E presented a proposal that would be an alternative tariff for just the three-cent surcharge revenues. The tariff includes some elements of a two-part critical peak pricing rate without use of a customer baseline or dependence on a real-time market index. It uses three different daily patterns of price and different quotas of days that would be in effect, which when weighted together would produce revenue neutral surcharge revenues. A customer representative expressed concern that it was not linked to market prices, and an ORA representative stated that customers might have a hard time determining the actual incremental effect of usage changes.
- AREM presented a sketch for a demand bidding program that would be open to both bundled service and direct access customers. One feature which attracted positive response from a customer representative was the use of capacity

reservation payments. The presenter asserted that these programs were received more favorably if they were operated by ISOs, rather than utilities.

- CEC presented a proposal for a Critical Peak Pricing (CPP) using a TOU rate, with two additional critical peak prices dispatched in response to wholesale prices or system conditions. One item of discussion was the importance of establishing very clear triggering criteria from the customer perspective and the utility perspective.

VIII. Applying Criteria to Tariffs/Programs

As noted III above, the presenters did a quick review of their proposals in light of the revised screening criteria matrix, essentially hitting obvious highlights. However, given the remaining time there was no discussion as to possible modifications to improve the proposal. This agenda item will be pursued again on October 2.

IX. Review of Revenue Neutrality Issues

No substantive discussion. Identified handouts from the CEC "Potential Revenue Impacts of Real-Time Pricing" by Braithwait, Chapman and O'Sheasy, and ORA's (Steve Ross) revenue neutrality primer. ORA's handout will be modified and re-circulated to WG 2. This topic will be addressed in more depth at the October 2 meeting.

X. Summary of Load Response from Experiential Workshops

No substantive discussion. David Hungerford announced that a document summarizing each presentation at the experiential workshops (prepared by Roger Levy) had been posted on the CEC website. All but one presentation are now on the website. Parties are free to review the summary report or workshop presentations to gather insights about tariffs in other states.

XI. Report Outline

No substantive discussion. Reference made to a proposed outline developed by SCE, which will be discussed at the next meeting in the context of a revised set of deliverables and schedule

XII. Review of Matrix Directed by September 5, 2002 ALJ Ruling

Moises Chavez of the CPUC's Energy Division handed out a list of data categories that are being contemplated for a demand response program matrix that has evolved out of direct in the ALJ ruling of September 5. Energy Division is seeking WG 2 input as to prioritizing these categories for the purpose of organizing the matrix. Working Group 2 agreed to prioritize the list using"high, medium, low" criteria, rather than ranking the categories numerically. Energy Division requested that responses be sent back to Chavez by Friday, September 27. An email will be circulated to everyone on the Working Group 2 list to ensure that all participants have received the priority list categories. Chavez also informed Working Group 2 that Energy Division will be seeking data input on the various cells in the matrix once it is ready for circulation.

XIII. Wrapup and Review

- Jaske will circulate electronically a revised Screening Criteria matrix.
- All those who presented a program/tariff are requested to fill out the matrix for their own proposal.
- Everyone in Working Group 2 is free to fill out the matrix for any proposal.
- The completed matrices should be sent back electronically to Jaske, Hungerford and Kaneshiro by Monday, September 30 so that they can be compiled and readied for discussion by the next WG 2 meeting (Oct. 2) with the goal of making a selection of 2-4 tariff/program types for further refinement.
- ORA will re-circulate its revenue neutrality primer for comment.
- The revenue neutrality issues will be discussed at the next WG 2 meeting.
- Jaske will check with the ALJ concerning schedule slippage and work product deliverables as an input into a WG2 discussion of these matters.

Working Group 2
October 2, 2002 Meeting Minutes

Getting Oriented

Meeting began with introductions. Three handouts were distributed to the participants: (1) Results of Using Tariff/Program Screening Criteria (spreadsheet), (2) ORA's Revenue Neutrality Primer, (3) Draft – Overview of Working Group 2 Topics and Schedule (spreadsheet). M. Jaske informed WG 2 that an ALJ Ruling would be issued later that day which will adopt an expanded schedule for WG 2 deliverables. Jaske also revealed that the ruling will clarify that WG 2 is expected to develop full-scale programs or tariffs, rather than pilots.

Review of Revenue Neutrality Issues

S. Ross (ORA) did a presentation on revenue neutrality issues. Basic definitions were provided for utility revenue neutrality and bill neutrality (no changes in the customer's behavior = no changes in the customer's bill). Ross also discussed issues that arise from the introduction of tariffs/programs which change customers' behavior: customers respond to new pricing signals by reducing their demand results in less revenue than anticipated for the utility. Customers who choose to move to a new pricing tariff could cause disaggregation of that customer class.

Ross also generally addressed implementation issues, such as designing new tariffs with either new billing determinants or with new revenue requirements. One point discussed by WG 2 is whether mandatory tariffs avoid the problem of class disaggregation, but also makes bill neutrality harder to achieve.

WG 2 participants engaged in a discussion about current rates. Customer group representatives in particular expressed the view that current rates have no relationship to costs, and thus rates designed to be revenue neutral in relation to current rates is a problem ('placing the cart before the horse'). Some skepticism was expressed whether this proceeding was the proper forum to modify revenue allocation to classes, and that dynamic tariffs might just as well accept current class allocations and let "macro" changes be decided in general rate cases or other forums. Various ideas were discussed such as creating two scenarios for WG 1 to consider: design a tariff that is revenue neutral in relation to current rates, and as a comparison, design a tariff that is based on existing costs. Some felt the issue should be kicked back to WG 1 for direction. There was no consensus achieved on the issue.

WG 2 participants also discussed whether any tariffs proposed by the group should be mandatory. No participant indicated support for mandatory tariffs, and the group agreed that all proposals going forward should assumed to be voluntary.

WG 2 participants discussed which cost components should have a dynamic price. Some participants felt that T&D charges and demand charges should be left alone, and that only the energy charge should have a dynamic price. Others felt that limiting the dynamic price to only energy charges makes potential savings for participants too insignificant to achieve a substantial interest in signing up for the tariff. Others felt that different customer groups will weigh the price savings differently based on load shape and other factors, and thus its difficult to generalize how customers will react until specific bill impact data is provided. Again, no consensus was reached.

Screen Tariffs/Programs

D. Hungerford (CEC) led a discussion on the spreadsheet entitled "Results of Using Tariff/Program Screening Criteria" which summarized assessments of 8 proposals (made at the September 25 WG 2 meeting) across several screening categories. The screening criteria were initially listed at the September 18 meeting, and modified substantially at the September 25 meeting. The summary used the screening spreadsheet sent out after the conclusion of the September 25 meeting. The point of the exercise was to identify which proposals 'stood out' in terms of positives or negatives with the ultimate goal being selecting only two or three proposals to go forward for detailed discussions. Only one entity evaluated any proposal other than its own, so the range of differences was very limited.

Policy Category:

The discussion focused on the CEC's two part RTP proposal as to whether the program was a reasonable starting point. The IOUs in general have concerns about two-part RTP, their primary concern being the development of the Customer Baseline Load (CBL). Specifically, the IOUs anticipate CBL development as costly, administratively complex, and potentially litigious (customers complaining about the CBLs a year later when their load shape has changed for different reasons). The IOUs cited their experience with the OBMC program as an example of how difficult a CBL development can be. The CEC countered that the current proposal was strictly historic for each customer, with a data variance exclusion to protect the UDC.

Some discussion focused on the criteria called "Compatible with other demand response programs". Some participants thought that incompatibility meant that a proposal had the potential to lure away customers from existing programs. Other participants did not see that as necessarily adverse (presuming that the new tariff/program was more cost-effective).

There was no clear consensus if any of the proposals were inferior or superior for this category.

Customer Choice Category:

Some discussion focused on the whether the two part RTP tariff would be difficult for customers to understand, and if some customers would need to hire professionals to effectively track information necessary for the tariff to be useful. The other proposals (with the exception of SDG&E's HPO pilot and the CEC's CPP) were all graded by their proponents as 'average' in terms of customer understanding.

Some discussion emerged regarding the likelihood of substantial customer participation, but participants appeared to have defined "substantial" in different ways, thus leading to differing opinions about the scores.

The discussion also moved to the issue of hedging and if that was an appropriate category to include in the Customer Choice category. Some participants felt that offering hedging opportunities with the proposals increases the chances of substantial customer participation.

There was no clear consensus if any of the proposals were inferior or superior for this category.

XIV. DR Potential Category:

Some discussion emerged as to amount and type of load reduction the proposals could deliver. Most of the proposal proponents provided no estimate on the amount of load reduction that their proposal could provide. The group also discussed the general categories of proposals in terms of their ability to target impacts to system needs. Generally, the more proposals make use of market prices directly and the less they are constrained by numbers of days of price patterns set in advance, the better they will target response to times when it is needed.

There was no clear consensus if any of the proposals were inferior or superior for this category.

Equity Category:

Discussion emerged regarding the issue of gaming opportunities. Some participants felt that gaming opportunities were insignificant for all of the proposals, and therefore not a relevant category to retain.

There was no clear consensus if any of the proposals were inferior or superior for this category.

Costs Category:

Some discussion focused on defining "high, medium, low" costs for the proposal proponents. In general proponents defined all costs (infrastructure, O&M, marketing/education) as incremental.

There was no clear consensus if any of the proposals were inferior or superior for this category.

Implementation Issues Category:

No specific discussion emerged for this category. There was no clear consensus if any of the proposals were inferior or superior for this category.

Conclusion:

SCE expressed willingness to modify its RTP-2 tariff to be triggered by some type of market price, and to drop its RTP-PX proposal. SDG&E expressed willingness to expand its recently approved RTP pilot to a larger number of participants provided that ratemaking practices were modified to limit unrecovered revenue requirement, e.g. preserve revenue neutrality.

The IOUs each felt that their proposals based on August 2001 submissions pursuant to D.01-08-021 were viable options for a WG 2 product and represents all that they think can be delivered by spring of 2003. SCE stated that if it had to rank its two RTP proposals, it would prefer RTP-2 over RTP-PX.

SCE believes that the modified Demand Bidding Program represents the best chance for a 'quick win'. Both SDG&E and PG&E expressed an openness to modify the Demand Bidding Program (as suggested by SCE) if more than one tariff/program is necessary for each utility.

One non-UDC participant challenge the UDCs to develop a proposal that could allow a true RTP tariff to be developed, e.g. estimating how much time and cost would be required.

Revised Schedule for Deliverables by WG 2

The spreadsheet "Draft – Overview of Working Group 2 Topics and Schedule" was passed out but the lack of time remaining prevented any substantial discussion about it. M. Jaske noted that the spreadsheet is designed to take advantage of the dual deliverables and extended schedule discussed at the previous WG2 meetings and authorized in the Oct. 2 ALJ ruling. Some parties expressed concern over the number of additional meetings, and one suggestion was made to remove some of the scheduled meetings, which would enable the parties to work more effectively. M. Jaske noted that the flow of activities embodied in the spreadsheet presumed a more engaged WG than has been evident to date, so some modifications will be needed.

Report Outline

No discussion due to the lack of remaining time.

Process for Obtaining Customer Feedback on Proposals

Discussion focused on the timing of receiving direct feedback from potential customers regarding the proposals. The customer representatives believed that there are not enough details in the proposals to get feedback at this time. When specific rate data can be developed for the proposals, customer feedback should be sought. Several customer reps reported that they cannot attend Oct. 11 WG2 meeting; suggesting deferral of this important input.

Wrapup and Review

M. Jaske informed the participants that the ALJ Ruling has been distributed that afternoon. Jaske advised that the ruling emphasizes that one size does not fit all, and thus the IOUs should be thinking of expanding their proposals to more than one. Jaske noted that the agenda for the next meeting (Oct. 11) will focus on price triggers. M. Jaske noted that the Oct. 15 WG1 meeting is being designed to focus on UDC presentations of their goals and constraints for this set of topics.

Working Group 2
October 11, 2002 Meeting Minutes

I. Getting Oriented

Mike Jaske led introductions and a review of the agenda. He also reminded attendees of the forthcoming WG1 meeting on October 15. He indicated to UDCs that this meeting would provide an opportunity for them to say what they want to get out of this proceeding. Finally, he indicated an agenda for the WG1 meeting would be released soon.

II. Demand Bidding Programs

WG 2 participants discussed SCE's proposal to modify the existing Demand Bidding Program: introduce a price trigger into the design of the program. Some participants felt that modifying an existing emergency-based program does not comply with past ALJ rulings for this proceeding. SCE is not recommending replacing the emergency-based trigger with a price trigger, and thus it believes its proposal does not violate past ALJ rulings. PG&E seemed to indicate its initial proposal was to replace the reliability trigger with an economic trigger since PG&E was not counting on anything from this program as a Stage 2 emergency reserve. Some participants felt that some direction on this question should be sought from WG 1.

SCE also noted that modifying the existing DBP w/ a price trigger represents the 'quickest win' because the customers and infrastructure for the program are already in place. If a price trigger is added to DBP, the IOUs prefer that they set the price that customers can respond to, rather than having customers setting prices for the IOUs to accept. The existing $0.35 per kwh rate that is offered by the DBP for emergency load reductions would not necessarily be the price trigger in a modified program.

WG 2 participants also discussed how DBP would fit within an IOU's procurement strategy. IOUs emphasized that they cannot at this time, rely upon the demand response programs that depend upon voluntary participation by customers as a dependable resource in procurement decision-making. While an IOU may have significant customer sign-ups, it remains to be seen whether customers would actually respond. IOUs believe that a track record of performance would need to be established first, before a demand response program can be considered a reliable resource that avoids firm resources.

John Flory made a presentation on the CPA's Demand Reserves Program (powerpoint slide handout). Flory noted that the IOUs would eventually take over DWR's role in the program when the IOUs become credit-worthy. At this time, no details were provided on how the transfer will occur. Flory also informed WG 2 that in addition to the Call Option and Ancillary Service options, end-users of the program might be given an additional option to bid into the ISO's Supplemental Energy Market (no capacity payments for this option). This additional option is currently under discussion with munies and direct access customers that cannot participate in the existing DWR/CAP program..

WG 2 participants discussed how the Demand Reserves Program would fit in with the IOU's demand response proposals. IOUs noted that there they do not have any programs currently where customers can bid into an ancillary services market, so there may be a niche. IOUs and John Flory agreed they could construct a matrix where the IOU's existing and proposed programs/tariffs could be compared to the Demand Reserves Program so that any gaps or overlap could be identified. They agreed to have the matrix ready for the rest of WG 2 by 10/23.

III. Developing Price Triggers for Dynamic Tariffs

There was limited discussion identifying appropriate price triggers for the IOU's proposals. PG&E's proposal is actually based on a temperature trigger. SCE did not identify any specific triggers for its proposal. SDG&E's proposal uses the average on-peak, day-ahead prices of three published indices.

WG 2 participants discussed the ISO's report that the FERC is requiring the ISO a zonal day-ahead market by the end of January 2003 (tariffs in place by the spring). IOUs are open to using the ISO's day-ahead market as a price trigger for their proposals.

WG 2 participants also discussed the concept of 'reliability adders'. The concept is that if demand response programs are not achieving a significant response in light of an impending Stage 2 alert, a reliability adder sends out an additional incentive to get a response. Some participants felt that this concept could be added as a separate tier later in the proceeding.

WG 2 participants also discussed how program participants are notified of prices. All of the IOUs employ the Internet as the primary means of notification. SDG&E also uses email.

IV. Two-Part Tariffs

The IOUs raised several implementation issues concerning two-part RTP tariffs. The development of the Customer Baseline Load (CBL) represents the most complex challenge. The IOUs also noted that only some customers over 200 kW have 12 months of data which would be necessary to construct a CBL, thus a phased implementation is likely. The IOUs also noted that there would be billing limitations that will affect the timing and degree of a rollout. Other participants acknowledge that these implementation issues are relevant, but not insurmountable. The IOUs urged that WG 2 defer on delivering a two-part RTP tariff for Phase I of the proceeding, primarily due to the complexity of designing it properly in the face of limited resources better deplyed with other programs to achieve a "quick win."

V. Wrapup and Review

M. Jaske reminded participants that the next meeting would be on Thursday, October 17 at the CPUC.

IOUs and CPA will provide a matrix of existing/proposed programs that will identify any gaps or overlaps with the CPA's Demand Reserve Program. Due: 10/23.

Working Group 2
October 17, 2002 Meeting Minutes

I. Getting Oriented

M. Jaske summarized the highlights of the Working Group 1 meeting that occurred on October 15. WG 2 participants discussed the idea of an interim decision in the winter to help resolve timing issues such as meter purchases in order to ensure a rollout by June 2003. The issue of delays for program rollouts seemed to be more of an issue for Working Group 3 than Working Group 2. Handouts included "Draft – Overview of Working Group 2 Topics and Schedule" (previously handed out at the October 2 WG 2 meeting), CEC's "Critical Peak Pricing: An Overview", SCE's "Real-Time Pricing Proposal" and "Draft Outline for Working Group 2 Report", and Lon House's "Public Customer Perspective".

II. Developing a Firm Schedule

WG 2 participants discussed specific expectations for the WG 2 report. Regarding the term 'tariffs', the expectation is not actual tariff language, but a description of the components of the tariff (triggers, eligibility, operations, etc.). The IOUs, via advice letters, would file specific tariff language after a Commission decision has been voted out. Regarding the marketing plan, the IOUs are not expected to provide the actual marketing instruments (fact sheets, brochures, etc.) for the WG 2 report, but rather a high-level description of their marketing efforts.

Participants discussed the possibility of developing a two-part RTP as part of the deliverables for Phase I. The IOUs shared that some preliminary analysis of available data suggests that many customers would not be able to qualify for the program as proposed by the CEC. The IOUs also expressed that due to limited resources and time, they could not commit to developing a two-part RTP along with their other proposals. The IOUs suggested that if WG 1 were to clearly make two-part RTP as the highest priority, they could shift their resources and concentrate upon its development, but that would mean dropping the other proposals. The IOUs will continue to conduct preliminary analyses of their data for a two-part RTP in the near term. Some discussion emerged about developing a two-part RTP tariff in early 2003, but one drawback is that PG&E's GRC would be in full swing, thus creating a resource limitation issue for that particular utility.

Participants discussed developing a CPP proposal for the WG 2 report as WG 1 principals noted a strong interest in this type of a program. Participants agreed to continue work on a CPP as a Phase I deliverable.

Regarding the specifics of the first deliverable (Nov. 15) of the WG 2 report, M. Jaske noted that each proponent would be responsible for an initial description of a tariff or program, leadtimes/barriers/limits to participation, and program costs (items listed in WG 2 Schedule Matrix). Depending upon the customer reaction to the proposals (discussed in Section V below), the internal due date for report drafts (Oct. 31) may need to be pushed back compressing review time. In order to keep to the schedule as much as possible, all proposals need to be close to their final versions by the next WG 2 meeting on Oct. 23.

Regarding the specifics of the second deliverable (Dec.13) of the WG 2 report, M. Jaske requested that participants review the items listed in the "Draft – Overview of Working Group 2 Topics and Schedule" (handout distributed on Oct. 2) starting at the bottom of page 4 through page 6. Comments on these items should be sent to M. Jaske by Monday, October 21.

III. Triggers for Dynamic Tariffs

Participants discussed the use of the ISO's anticipated day-ahead market. In general the IOUs indicated that assuming the ISO's day-ahead market is healthy and robust, they would prefer using that market as a price trigger as opposed to price indices like those used in SDG&E's HPO pilot. The participants discussed when it could be determined that the ISO's day-ahead market was indeed healthy. It appeared that waiting until the end of the summer of '03 would be an adequate amount of time to assess that market.

SCE provided further details regarding its RTP proposal (handout). Specifically SCE proposes that its hourly energy price schedules are triggered by a day-ahead electricity price (based on the ISO or other published index).

CEC's P. McAuliffe provided a quick summary of the CEC's CPP proposal (handout). Discussion focused on how the CEC's CPP proposal differed from PG&E's temperature-triggered proposal. The CEC's proposal differs from PG&E in that it has multiple triggering mechanisms such as day-ahead prices, system reliability alerts, and local reliability events. Further, in the CPP proposal the energy rate only changes for critical events, rather than the entire daily TOU charge structure as in the PG&E proposal. One point raised by customer representatives is that potential customers would be more receptive to the CEC's proposal if there were clearly limits placed on the frequency or number of days in a row that critical peak prices are triggered.

B. Barkovich (CLECA) made a proposal to consider a pricing program that provides an incentive for participants to increase consumption in those hours when the system is overscheduled and the ISO is paying generators to "dec" their schedules. It was observed that this seems to rely upon a two-part RTP tariff with additional consideration in setting prices to include ISO payments that might not be part of a Day Ahead market price.

IV. Key Implementation Issues for Each Proposal

Due to the remaining time, the discussion focused on two sub-topics: lead time from CPUC decision to recruitment, and data processing/limitations on participation.

Lead time issue: IOUs stated that if a Commission decision is authorized by February 1, the IOUs would have their proposals in operation by June 1, meaning that recruitment and marketing of the programs would have largely been completed by then. Delays in the Commission decision would push back the operational date, or would reduce the amount and quality of recruiting and marketing efforts. Also, for PG&E specifically, a slip in the operational date may have an effect on its program because of the quarterly basis for the linkage among different "day types" triggered by temperatures.

Data processing limitation issue: the IOUs do not anticipate data processing limitation issues for their programs as the anticipated sign-up is not expected to reach the level where there would be implementation problems.

V. Process for Getting Input from Customers

The participants focused on what would be most helpful in getting feedback from potential customers on their proposals. The customer representatives emphasized that program/tariff descriptions are a helpful starting point, but do not provide the specific information that customers need to evaluate a program. The customer representatives emphasized that customers need to see how the program/tariffs translate into bill impacts using a variety of load profiles; customers are most interested in seeing how the new rates compare to the existing ones in terms of impact upon their bills.

In order to provide this type of information, the IOUs would need to have a model in which to run through a load profile. SCE indicated that it was willing to provide 4 load shapes using its proposal with comparisons to existing rates. SDG&E could possibly do the same but not until the end of October. PG&E indicated that it could not provide the same level of detail as the other utilities as it does not have a model developed for its particular proposal.

In order to stay consistent with WG 2 schedule for deliverables, M. Jaske requested that the IOUs provide to the customer representatives (and all others in WG 2) their latest, most specific program descriptions and to the extent that they can provide rate comparison information, that type of information as well. The IOUs should distribute this information by Wednesday, October 23. The IOUs were also encouraged to try to make their information standardized to the extent possible so that the proposals could be compared fairly.

The participants agreed that a meeting after October 23 should be focused on hearing from potential customers once they have had a chance to digest the information sent. It was agreed that the meeting on October 30 would be an appropriate time to do this. But due to a scheduling conflict, it was also agreed that the October 30 meeting would be switched to November 1 (in Sacramento).

VI. Two-Part RTP Tariffs

This topic was discussed in Section II. A schedule for a two-part RTP tariff deliverable will be decided at the next meeting.

VII. Wrapup and Review

The next meeting (Oct. 23) is scheduled to be in San Francisco at the CPUC.

Action Items:

- Second deliverable for the WG 2 report. WG 2 participants review the items listed in the "Draft – Overview of Working Group 2 Topics and Schedule" (handout distributed on Oct. 2) starting at the bottom of page 4 through page 6. Comments on these items should be sent to M. Jaske by Monday, October 21.

- By Wednesday, October 23, the IOUs provide to the customer representatives (and all others in WG 2) their latest, most specific program descriptions and to the extent that they can provide rate comparison information, that type of information as well. The IOUs are encouraged to try to make their information standardized to the extent possible so that the proposals could be compared fairly.

- The WG 2 meeting scheduled for October 30 will be moved to November 1. Location will be Sacramento.

- Customer representatives should try to get customer feedback in preparation of the November 1 meeting (in Sacramento), and to possibly invite customers to participate at that meeting.

Working Group 2
October 23, 2002 Meeting Minutes

I. Getting Oriented

Several handouts were provided: an assignment and due date matrix for the WG 2 report sections (CEC), "CA Non-Pricing Demand Response Programs (Existing and Proposed)" (SCE), "Real-Time Pricing Proposal Schedule RTP-Market Index" (SCE), "Demand Bidding Program Proposal Schedule DBP – Market Price" (SCE), "RTP Customer Profile" (SCE), "Hourly Pricing Option – Illustrative Bill Impacts" (SDG&E), "Hourly Pricing Option – Pricing Pilot Program" (SDG&E), "Critical Peak Pricing and Critical Peak Demand" (CEC), "Critical Peak/DWR Bonus Tariff Proposal" (ACWA), "Demand Bidding Program Proposal" (PG&E).

II. Finalizing Schedule for Meetings and Deliverables

M. Jaske reported that he received no significant comments (comments were due on Monday, Oct. 21) from WG 2 participants regarding the WG 2 schedule matrix (circulated on Oct. 2, and discussed at the Oct. 17 meeting) for deliverables due on November 15 (1st report) and December 13 (2nd report).

Participants discussed the CEC's WG 2 November 15 Report assignment matrix. Questions arose about Section II (Experience with Dynamic Tariffs/Programs) where some participants expressed concern as to whether this section was intended to be a factual summary of programs (within and outside of the U.S.) or whether the section would contain conclusions as to what can be learned from these programs. Some participants felt that because WG 2 has not spent time discussing out-of-state programs, they would feel uncomfortable with a section that made conclusions about the applicability of out-of-state programs to California.

The IOUs requested clarification of Section VI (Generic Implementation Issues). CEC and CPUC staff explained that this section was intended for the IOUs to discuss implementation issues beyond their specific proposals, such as implementing proposals besides their own. The section was also intended to be place for a discussion on broad issues not tied to any specific proposal such as cost recovery, or back-office capabilities.

Under Section III (Fundamental Considerations), one participant recommended that an additional sub-topic on Direct Access Issues be included. (Sub-section "E.")

A question arose about where the topic of infrastructure would be addressed in the report. CEC staff explained that under Section V (Specific Proposals), each proponent would describe the necessary infrastructure for their proposal.

The group discussed how the report's Recommendation (Section VII) would be drafted. Some participants expressed concern that the report would be limited to just a menu of options, while the IOUs were concerned about having an opportunity to comment on implementing proposals they have not advocated. All participants will have opportunity to review and comment on draft sections of each chapter, and will also have an opportunity to file comments on the report once it is made public. The group also agreed that each participant can send in their recommendations to M. Jaske who would attempt to compile and summarize them as part of the report.

ORA volunteered to do a write-up on a two-part RTP tariff that describes where WG 2 is today regarding this tariff, and the issues that would need to be addressed going forward. Participants agreed that ORA's write-up could be added as a final piece to Section V of the report. One item of discussion for a going-forward plan was successfully identifying customers who would most likely be interested in a two-part RTP. A committee was also formed that would meet after November 15 to discuss this topic further. The committee includes ORA, CLECA, ACWA, DGS and the IOUs.

The assignments for the November 15 WG 2 report along with due dates for circulation to the group are attached as an Appendix to these minutes.

Regarding the December 13 deliverable, participants were reminded that it is currently planned to have two major sections: a discussion of marketing/education plans and a cost-effectiveness assessment. C. King and S. Anderson have offered to develop the cost-effectiveness assessment and noted that they will need information from the IOUs. It was agreed that they should meet and report back to WG 2.

III. Review of Dynamic Tariff Proposals

L. House (ACWA) made a presentation on a CPP proposal (handout). The proposal contains two major components: a 4 hr. peak period and a 4 cents/kWh price reduction when selling DWR electricity for increased customer demand. The IOUs expressed concern noting that the price reduction concept is not fully developed, which House acknowledged. The IOUs also were reluctant to redefine the peak period from 6 hours to 4 hours. House emphasized that a 6-hour peak is too long for most customers.

Pat McAuliffe (CEC) made a presentation on the CEC's CPP proposal having taken into consideration comments received at the previous WG 2 meeting. The proposal moves 79 hours from existing on-peak hours to a critical peak period. On-peak prices are then reduced (from $65 per MWh to $54 per MWh) while the critical peak price is $146 per MWh. McAuliffe then developed an 'adder' to the new rates to ensure revenue neutrality, based on an existing tariff. The adder is quite large compared to the underlying assumptions regarding wholesale electricity prices. Participants discussed whether a CPP proposal is viable for implementation by the summer of 2003 given that tariffs are higher than current market prices. Participants noted that existing rates include "stranded assets" or debt, which make design of dynamic pricing tariffs very difficult in the short run. In part, this difficulty is based on whether utility costs are avoidable or not. Some suggested that the IOUs' GRCs are a more appropriate forum for this issue to be resolved, and others noted that an attempt in this proceeding to do massive rate re-design will run into scoping and notice issues. This is the same as the issue raised at the WG1 meeting on October 15, but not resolved.

McAuliffe also made a presentation on a concept called "Critical Peak Demand" where demand charges would be converted to a time-related basis using a limited number of hours in a critical peak demand period. Chris King offered a variant in which the demand charge would remain unchanged in bill calculations, but the energy-equivalent price would be provided to customers to simply their assessment of when to respond. The IOUs expressed reservations about changing demand charges as these charges are largely based on fixed costs.

There was no remaining time to review the handouts provided by the IOUs for their proposals. M. Jaske requested that all proponents circulate via email the specific information covered under sub-sections B through F of Section III in the agenda. The information should be circulated by Friday, October 25, or as soon thereafter as possible to the updated WG2 email list. Along with that material, proponents of tariffs or programs should email their actual proposal and quantitative assessments to ensure that everyone receives complete materials.

IV. Review of Load Bidding Program Proposals

M. Wallenberg (SCE) made a presentation on revising the existing Demand Bidding Program (DBP). The proposal allows participants to voluntarily reduce demand when the ISO day-ahead or day-of market prices equals or exceeds $250 per MWh for any hour. The ISO commented that existing rules prohibit the ISO from accepting a price that exceeds $250 per MWh. M. Jaske inquired whether the fact that the ISO cap is a soft cap, thus allowing for bids above $250 per MWh, would mean that the ISO would compute and release an implicit price series that could be the basis for load bidding payments. The existing DBP is based off of a reliability trigger and SCE is not sure if that trigger should be removed or kept with a price trigger.

PG&E indicated that its proposal for DBP would be the same as SCE's, and SDG&E in not now advocating conversion of its DBP, but would not be opposed to implementing the change as suggested by SCE.

The participants discussed the Power Authority's Demand Reserves Program and how that fits with existing and proposed demand response programs. The IOUs in general believe that there is a place for the Demand Reserves Program in that its focus on the Ancillary Services market is not duplicated by any existing or proposed proposal (handout of existing IOU programs compared to the Demand Reserves Program). In regards to the assignability of the contract between DWR and the CPA, the IOUs noted that they are addressing implementation and legal issues in the CPUC's procurement proceeding. The CPUC's anticipated decision in that proceeding (set for Oct. 24) may answer some unresolved questions and WG 2 can go from there.

V. Process for Getting Input from Customers

Due to the lack of time, this topic was not discussed in detail. As noted, the November 1 meeting will have a major focus on customer input, either via customer group representatives or customers themselves. Each tariff or program proponent should be prepared to make a five minute overview presentation to be followed by Q&A from customers or customer representatives. The proposed agenda for November 1 will provide more guidance on the precise format to be followed.

VI. Wrapup and Review

- Next meeting is scheduled for November 1 in Sacramento. The focus of the meeting is to hear feedback from customers on the proposals. The location is:

  Twin Towers – Social Services
  744 P Street
  First Floor Auditorium, Room 102
  Sacramento
  (This is about one block to the west and south of the CEC Building)

- The meeting scheduled for November 6 will be moved to November 12. This change will enable participants more time to review the WG 2 report drafts. The focus of the November 12 meeting is to discuss issues prior to the publication of the WG 2 report. Location for this meeting has yet to be determined.

- The WG 2 email distribution list has been revised several times to include additional names and addresses. WG2 participants are encouraged to update their email lists to conform to that the appropriate people get the materials of the WG. A revised list will be re-circulated by Friday, October 25.

- Due to email distribution problems, all proponents should re-distribute the specific details of their proposals to the revised WG 2 list. Specific rate analyses and comparisons should also be provided to the extent practicable. This information should be circulated by early next week so that customer representatives can distribute the information to prospective customers prior to the meeting set for November 1.

- All drafts for the WG 2 report should be circulated to all participants on the WG 2 email list for review by the dates noted in the assignment matrix (attached).

WG2 Report on Tariffs/Programs and Implementation Barriers
Due November 15, 2002

Report Section/Subsection	Author	Draft Due*	Review Due
VI. Executive Summary	Not assigned		
VII. I. Introduction			
A. Mission for >200 kW Customers	C. King/M. Jaske**	10/31	
B. Nature of the WG Process	" "	10/31	
C. Role of this Report	" "	10/31	
II. Experience with Dynamic Tariffs/Programs			
A. In California	A. Bell/ C. King	10/31	
B. Outside California	" "	10/31	
III. Fundamental Considerations			
A. Economics vs. Reliability	C. Blunt	10/31	
B. Revenue Neutrality	"	10/31	
C. Voluntary vs. Mandatory	"	10/31	
D. Customer Interest	B. Barkovich/K. Lindh	10/31	
E. Direct Access Issues	B. Barkovich/G. Lizak	10/31	
IV. Screening Process			
A. Rationale for Criteria	CEC Staff	10/31	
B. Results of Screening Process	CEC Staff	10/31	
VIII. V. Specific Proposals			
A. Proposal #1	All proposal proponents	11/5	
(1) General Description	" "	"	
(2) Eligibility	" "	"	
(3) Source of Drivers/Triggers	" "	"	
(4) Intended Level of Participation	" "	"	
(5) Sources/Levels of Cost	" "	"	
(6) Method of Cost Recovery	" "	10/31***	
(7) Linkage to Procurement Activities	" "	"	
(8) Estimated Start Date	" "	"	
(9) Proposed Method of Implementation	" "	"	
(10) Lead Time from Approval	" "	"	
(11) Other Implementation	" "	"	

Issues			
B. Proposal #2, #3, #4, etc.	“ “	“	
C. Two-Part RTP Status	ORA	10/31	
VI. Generic Implementation Issues			
A. UDC Back Office Capabilities	IOUs	???	
B. Cost Recovery	ORA & IOUs	11/5	
C. Other Non-Specific Issues			
VII. Recommendations	All participants	10/31	
APPENDICES			
A. Details of Screening Process			
B. Matrices of Instate/Out-of-State Tariffs and Programs			
C. ?			

* Draft must be circulated to all participants on the WG 2 service list.
** B. Kaneshiro (CPUC) will likely replace M. Jaske for this section.
*** UDCs were requested to provide a draft of this section to ORA to enable ORA to complete its overview product for section VI.B by 11/5.

Working Group 2
November 1, 2002 Meeting Minutes

I. Getting Oriented

Several handouts were provided; some of these were duplicates of handouts provided at the October 23 WG 2 meeting: a revised assignment and due date matrix for the WG 2 report sections (CEC), "Real-Time Pricing Proposal Schedule RTP-Market Index" (SCE), "Joint Utility - Demand Bidding Program Proposal October 31, 2002" (SCE), "RTP Customer Profile" (SCE), "Hourly Pricing Option – Illustrative Bill Impacts" (SDG&E), "Hourly Pricing Option – Pricing Pilot Program" (SDG&E), "Critical Peak Pricing, A Proposal" (ACWA), "Example Calendar for PG&E's Proposed Summer RTP/CPP Price Signals" (PG&E), "California Demand Reserves Partnership – October 28, 2002" (CPA).

II. Getting Input from Customers

There were a total of seven proposals presented to WG 2.

a. SDG&E's Hourly Pricing Option

SDG&E summarized the operation of the tariff and presented potential bill impacts for six different load shapes: grocery store, office building, refrigerated warehouse, department store, large restaurant and water district. SDG&E is willing to expand the program from the 35 customer, 50 kW limitation to customers with over 300 kW demand (potentially 1,300 customers).

Customers noticed that the HPO tariff produced negative results for four of the six load shapes (assuming no shifts in load). SDG&E's analysis showed that if a customer decreased on-peak consumption by 5% and increased off-peak consumption by 5%, two of the four negative results would turn positive. Customers commented that the amount of savings calculated using SDG&E's analysis does not appear to be high enough to attract significant amounts of participation.

Customers also suggested that they need more specific information on the amount of load shifting and/or reduction necessary for savings in order to make a decision to participate. It was noted that customer support tools of this sort are included within the scope of the marketing and customer education plan issues that must be discussed and then described as part of the December 13 deliverable. A policy decision about the extent of such support, and how to pay for it, needs to be made.

b. SCE's RTP Proposal

SCE summarized the operation of the tariff and provided load profiles of three customer types on its TOU-8 tariff: office building, cement company, and hospital. SCE also compared potential savings/costs for these customer types if they participated on the proposed RTP tariff using two scenarios: 15 days and zero days of extremely hot weather. The analysis demonstrated that with zero extreme days, all of the customer types achieve savings should they switch to the proposed RTP tariff. Using the 15 day scenario, only the cement company is able to achieve significant savings. Commissioner Rosenfeld asked whether an "expected" number of days would reveal any different results. SCE was unsure.

Customers suggested that SCE's marketing effort should provide more information about actual amounts of load that must be shifted or reduced in order for customers to decide whether to participate. Customers also noted that while rate comparisons are helpful, such information has to be translated into operational costs for customers to judge the tradeoffs of switching tariffs. Once again, this is an issue for future discussion as part of the marketing and customer education plan topic, beginning at the November 12 WG2 meeting.

Some customer participants noted that SCE's proposed tariff rewards customers with certain load profiles (cement companies) while others customers who lack the ideal load profile will lose or not participate. This led to a discussion about the issue of 'free riders' (participants do not make shift or reduce load but are able to achieve savings from the tariff). Customers emphasized that some customers may consider investing in technology or infrastructure so that they can modify their load shapes to participate. However, that decision can only be made if the state signals a commitment that these demand response tariffs will be in place for at least 5 years or more. Uncertainty about the future of these tariffs leaves companies vulnerable to not recovering their investments.

Representatives of office building customers commented that SCE's proposed tariff has very little appeal given their typical load shape.

c. PG&E's Summer RTP/Critical Peak Pricing Proposal

PG&E summarized the operation of their RTP/CPP proposal and noted several changes since the previous version was distributed: (1) greater difference between normal and low price days, (2) operation limited to four summer months, not year round, and (3) somewhat different numbers of days per day type. PG&E also provided a comparative analysis using a random selection of customers currently on PG&E's E-20 tariff. In general, the analysis showed that if office buildings participate, they must reduce their load significantly on high peak days to avoid higher bills. In general, assembly-industrial customers could actually increase their loads on high peak days and still break even.

Some customer representatives commented that PG&E's proposal is preferable over SCE's in that more risk is minimized, although the incentives offered by PG&E are not great. Some customer representatives were concerned that office buildings are at a disadvantage with this proposal (similar to SCE's), and noted that many "industrial" customers in Silicon Valley are predominately "office" buildings. In response, PG&E noted that a "stair step" of hour-specific prices could be used for the critical peak period, which would focus attention on a few hours and perhaps be easier for "on peak" customers like office buildings to reduce load in just these hours.

d. ACWA's Critical Peak Pricing Proposal

L. House summarized how ACWA's CPP proposal would operate. The generation portion of the "on peak" demand charge would be eliminated and converted into an energy charge for just the critical peak hours. There would be six or more of these each month. The energy charge would be designed to recover the same revenue as the displaced portion of the demand charge when operated for six hours. Customers would be given a credit for each of $1.00 per KWh for each hour in which the average load in the CPP period was less that the average load in the peak demand period.

The one feature of the proposal that drew most of the attention is that customers can do no worse on the proposed tariff than their current tariff. While customer representatives noted that this feature would attract potential participants, the investor-owned utilities expressed skepticism as to how the proposal would work, how the credit would be computed, and about the revenue loss from participants that seemed inherent in the proposal because of its "do nothing, lose nothing" design.

e. CPA's Decremental Energy Credit – Addendum to ACWA's CPP Proposal

J. Flory provided a quick summary of the CPA's proposal to add a load building incentive onto the ACWA CPP proposal. Essentially, this would create a "critical trough" component that complements the "critical peak" component. Flory explained how the how an additional energy credit would operate. A somewhat confused discussion could not resolve how to track who was winning and losing under this proposal, due to the complexities of the DWR versus UDC portions of revenue requirements situation once UDCs resume procurement on 1/1/2003. SCE doubted that this feature could be implemented by the summer of 2003, and suggested that it would be preferable to fold this concept into the two-part RTP process for next year.

f. Joint IOU – Demand Bidding Program Proposal

The three UDCs jointly submitted a revised Demand Bidding Program that had evolved as a result of the discussion at the October 23 meeting. SCE summarized how the revised DBP would operate. The program would have both a price trigger and an emergency trigger. If actuated for reliability purposes, as it is today, customers would be paid $0.35 per KWh. If actuated for economic purposes, the customer would be paid the higher of $0.15 per KWh or the ISO market clearing price, whichever was greater.

The feature receiving the most comment is the use of 10-day rolling baseline to determine the customer's actual reduction in load. Customer representatives believe that the 10-day rolling baseline is not an equitable means of determining actual reductions and some suggested that the baseline can and should have adjustments (such as for temperature sensitive customers). Participants noted that the CEC had funded research into baselines, and that the resulting report has suggested that a two-part baseline methodology was preferable. Part one is the current ten-day rolling average by hour method. Part two scales this load shape to the level of load measured during the morning of the day the program is operated. The differences from current baselines in CPUC-authorized programs were noted.

g. CPA's Demand Reserves Program

J. Flory quickly summarized the program. The CPA believes that the DRP will soon become a procurement tool for UDCs to use in satisfying their resource and reserve needs. The CPUC's recent procurement decision indicates a favorable stance on assigning the program to the IOUs once they become credit-worthy, but the language of the decision also implies that the CPUC has not yet approved assignability.

III. Review of Progress on 11/15 Report

M. Jaske took inventory from the section authors to gauge progress. The following was reported:

Section I: sent to M. Jaske, but not circulated to WG 2.
Section II. Part A: no draft yet
Part B to M. Jaske, but not circulated to WG 2
Section III. Parts A-E circulated to WG 2
Section IV: no draft yet
Section V: all proponents reported that they will file their write ups by November 5
Sections VI: ORA included an RTP "follow on" task in its writeup of Section III
Section VII: a single set of recommendations has been prepared by SCE.

Participants discussed the status of the two-part RTP. Participants envisioned another WG 2 work product in 2003, but no specifics were discussed. One idea discussed was developing a small two-part RTP pilot in time for the summer '03, but the majority of participants felt that there were too many barriers to attempt to do that, since the developmental issues to be surmounted were the same in small volumes as larger ones.

CEC and CPUC staff took on the responsibility of merging all of the sections into a single report. Assuming that all the sections are timely submitted, a 'merged' draft would be circulated to WG 2 by November 6. Participants were encouraged to review the draft and provide clarification comments (directly to the authors but also circulated to all other participants). Participants were also encouraged to provide suggested changes as part of their comments rather than limiting their comments to just criticism. Authors were encouraged to take into consideration all comments received and make changes, as they felt appropriate. Another draft of the full report would be circulated to WG 2 by November 12, meaning that changes by the authors to existing sections need to be sent to M. Jaske/B. Kaneshiro by noon, November 8. The largest portion of the WG2 meeting scheduled for November 12 will be devoted to discussing the report before it is filed on November 15.

WG 2 participants also agreed participants may file dissenting opinions regarding any section in the report. These opinions should identify the participant(s), and their specific issue. Assuming these opinions are provided in a timely fashion, they will be attached to the section of the report that they address. (For example, if a participant takes issue with a particular proposal in Section V, that participant's dissenting opinion will be inserted after that particular proposal in Section V.) If participants recognize that they have the same position, they may also file joint comments. Participants were also reminded that they may also file dissenting opinions during the report comment period.

IV. Looking Ahead to December 13 Report

M. Jaske handed out a revised scheduling worksheet that identifies an alternative set of discussion topics leading up tot he filing on December 13. Due to the lack of time, this topic was not discussed except to note the revised meeting dates. A portion of the meeting on November 12 will be devoted to the topics covered in the Dec. 13 report. In general each of the three main elements of that report will be discussed at that meeting to set the stage more in depth discussions on November 19 and December 3 meetings.

V. Wrapup and Review

- Next meeting is set for November 12, at the CEC's Hearing Room A. The focus of the discussion will be on finalizing the report due on November 15 and to begin discussions on the topics covered in the December 13 report.

- Assigned authors for the report need to circulate their sections by close of business, November 5.

- CEC and CPUC staff will compile all of the sections into one report to be circulated by November 6 (assuming all the sections arrive in a timely manner).

- Participants are encouraged to provide specific suggestions to the authors rather than criticism. Clarifying comments and edits should be circulated to the authors and all other WG 2 participants by November 7.

- A revised draft (that includes any revisions, clarifications to the original writeups) will be circulated by the November 12 meeting.

- Authors should send any changes to the CEC and CPUC by noon, November 8 in order for those changes to be incorporated for the November 12 revised draft.

- Dissenting opinions will be inserted into the sections of the report that they address, and dissenters will need to identify themselves.

Working Group 2
November 12, 2002 Meeting Minutes

I. Getting Oriented

Five handouts were provided: meeting agenda, WG 2 draft report discussion agenda, email sent by Andrew Bell (PG&E) providing comments and recommendations for the WG 2 report (dated November 8, 2002), email and printout of updated Section II and Appendix C for the WG 2 report from Andrew Bell (dated November 11, 2002), and a proposed schedule for the Cost-Effectiveness Study (Stan Anderson).

II. Review of Draft 11/15 Report

WG 2 discussed a going-forward plan for finalization of the report. M. Jaske noted that CEC/CPUC staff intends to distribute an updated draft of the report by noon, Wednesday for participants to review. Any final edits by section authors should be provided to agency staff by Wednesday morning for incorporation. Participants were instructed to provide final comments and alternative viewpoints back to the agency staff by mid-day Thursday for incorporation into the final draft. Participants were advised to make their comments specific, and to provide suggested text changes for those parts of the draft that they would like to see modified. Alternative viewpoints should have headings for those sections of the report that they address so that agency staff will know where to insert them. Alternative viewpoints should not be an analytical critique, but limited to a short paragraph expressing a different view.

WG 2 focused on specific sections of the report as follows:

Section V.D (ACWA's CPP Proposal): PG&E recommended that this proposal be withdrawn noting that there are undercollection and self-selection issues with the proposal. ACWA was not represented at the meeting, but in an email (dated Nov. 8) to WG 2, Lon House (ACWA) disputed PG&E's points, and thus refused to withdraw the proposal. WG 2 participants agreed that it is up to each proponent to decide if its proposal should be withdrawn from the report.

Section V.F (CPA's Demand Reserves Partnership): PG&E recommended that this proposal be withdrawn from the report noting there are issues concerning its assignability, its cost-effectiveness and its enrollment levels. John Flory (representing the CPA) provided a presentation responding to PG&E's points. Flory decided not to withdraw the DRP from the report.

Section V.G (IMServ's Direct Access Proposal): PG&E recommended that this proposal be withdrawn from the report because WG 2 has not had the opportunity to fully deliberate over it. G. Lizak (IMServ) anticipates that the National Energy Marketers will endorse the proposal. Lizak also agreed to withdraw the proposal from the 11/15 report, but expressed that it should be included as a pilot proposal for the 12/13 report. WG 2 participants agreed to take up discussions of the proposal at a future WG 2 meeting.

Executive Summary: B. Kaneshiro (CPUC) reported that a draft of the ES would be distributed with the rest of the report at Wednesday noon.

Section II (Experience w/ Existing Demand Response Programs): A. Bell (PG&E) reported that Section II.A was circulated on Monday (hard copies provided at the meeting) and is ready for inclusion into the report. SCE felt that Section II contained inappropriate conclusions and specific words that were misleading and inconsistent with other sections of the report. SCE agreed to work w/ the section's primary authors (PG&E and C. King) to come up with language that was acceptable.

Section V.H (Two-Part RTP Development): The IOUs were concerned with ORA's proposal that WG 2 deliver a two-part RTP tariff for Commission consideration by April 15, 2003. The IOUs noted that more time would be needed to address the baseline and market price issues. Customer groups noted that discussion of baselines is often contentious and they would prefer spending more time on getting it right, than getting it done quickly. WG 2 participants agreed that October 1, 2003 was an acceptable date for implementation, and that the specifics leading up to that date should be further scoped by the group.

Section VI.A (Data Processing/Billing Constraints): The IOUs noted that they are positioned to implement their own proposals without implementation problems in data processing or billing. However the IOUs also noted that if the Commission were to adopt multiple programs, there would be implementation issues. Further, the IOUs have not evaluated ACWA's proposal in terms of data processing and billing implementation. WG 2 concluded that given the amount of time remaining, it made more sense to defer this section to the December 13 report. The IOUs were advised that they must address all of WG 2's proposals in light of data processing/billing constraints in order for WG 1 to be fully informed.

Sections III.D and III.E (Customer Interest and Direct Access): duplicative pieces were written for these sections. The authors (ORA, CLECA/CMTA) agreed to develop a text that merges the write-ups.

Section IV (Screening Process): SCE proposed that this section be withdrawn, stating that it had no apparent relevance to the report. SCE also disagreed with how the section characterizes the screening process. CEC staff agreed to review the section and make some text changes in light of the comments, but it will be retained as part of the report..

Section VII (Recommendations): WG 2 participants discussed the 12 draft recommendations provided by SCE and CCEA, and agreed to 6, with some text modifications. The remaining draft recommendations could not achieve consensus or were considered more appropriate for the December 13 report.

Section VI.B (Cost Recovery): ORA reported that it had summarized the IOU's proposed cost recovery mechanisms, and noted that there are differences among them. IOUs agreed that they would discuss amongst themselves if common mechanism can be agreed upon and would work with ORA in developing a final draft for this section.

III. Marketing and Customer Education

WG 2 participants discussed this topic in general; IOUs shared that the standard marketing/education procedure is to use their own account executives as they have the most familiarity with each customer. IOUs also work through customer group associations to spread the word. IOUs noted that they identify the target customers who would most likely find a tariff/program appealing and then tailor the marketing effort accordingly. Some coordination with marketing new tariffs/programs and existing reliability-based programs will be necessary.

IV. Developing Range of Estimates

This topic was discussed in the context of Agenda Item V, Conducting Cost-Effectiveness Tests for Each Proposal.

V. Conducting Cost Effectiveness Tests for Each Proposal

S. Anderson (Power Value, Inc.) provided an update on the cost-effectiveness analysis. A sub-committee consisting of the proposal proponents and Anderson met on November 1 to scope out a framework and schedule. WG 2 reviewed and discussed a proposed schedule that provides a cost-effectiveness analysis for the December 13 report. Anderson proposes to use a modified Standard Practices Manual (SPM) as the framework for the analysis, which he intends to distribute on November 13.

WG 2 participants discussed some potential drawbacks of using the SPM, and Anderson noted that at least one proposal proponent (SCE) prefers another approach. It was unclear whether SCE will pursue an alternative approach in parallel with that agreeable to the overall C/E team.

Anderson noted that he needs various data inputs from the proposal proponents by November 18 in order to stay on schedule. The most challenging inputs would be anticipated load and scaling data. WG 2 participants discussed providing a range of data, as it may be difficult to predict specific numbers. IOUs recommended that Anderson provide a matrix or format so that the data inputs are comparable. Anderson agreed.

VI. Evaluation and Evaluation Plan

WG 2 did not discuss this agenda item as there was no time left in the meeting. The item was deferred until November 19.

VII. Wrap up and Review

- Next meeting is set for November 19, at the CPUC (either the Auditorium or Hearing Room A).
- Proposal proponents should be prepared to discuss specific marketing/customer education plans, their implications for describing a range of impacts, and program/tariff evaluation plans on November 19.
- Agency staff will circulate an updated version of the draft report by noon, Wednesday, November 13 for final review by WG 2.
- Final comments/edits and alternative viewpoints must be submitted to agency staff by 1 pm Thursday, November 14. Items arriving after that time might not be included in the final draft.
- S. Anderson will circulate a cost-effectiveness tool with a data input matrix for proposal proponents to use in providing their inputs for the analysis.
- Proposal proponents must provide their data inputs to Anderson by November 18.
- Section VI.A (Data Processing/Billing) is deferred to the December 13 report. IOUs are expected to evaluate all WG 2 proposals.

	BG&E - Market Based Load Response	Cinergy - PowerShare Pricing	Duke - Real Time Pricing	Georgia Power - Real Time Pricing	ISO NE - Price-Based Demand Response	ISO NY - Price-Based Demand Response
Program Goals	Allow customers to save by reducing demand when wholesale prices are high	Realize peak demand reductions in response to price incentives	Provide full-time energy price signals	Provide full-time energy price signals	Realize peak demand reductions in response to price incentives	Realize peak demand reductions in response to price incentives
Strategy-Results	Pricing	Pricing, focus is critical peak hours up to 96 per yr.	Pricing; yields predictable demand response to day ahead hourly prices. Elasticity increases on the order of 0.03 with each additional year of experience on the rates.	Pricing, real-time pricing; yields predictable demand response to day ahead hourly prices	Pricing	Pricing
Key Customer Requirements	Must be able to reduce peak load by 25 kW					
Status & History	Operational since 2000	Operational as of 2000	Operational since 1997	Operational since 1990	Operational as of 2001	Operational as of 2001
Pilot History (if any)						
Load Shape						
Seasonality	Year round	Year round	Year round	Year round	Year round	Year round
Parties Involved	Customer, IOU	Customer, IOU	Customer, IOU	Customer, IOU	Customer, NE ISO	Customer, NY ISO
Marketing Responsibility	IOU	IOU	IOU	IOU		
Region	MD	OH, IN	NC	GA	New England	NY
Voluntary vs. Mandatory	Voluntary	Voluntary opt-in	Voluntary opt-in	Voluntary opt-in	Voluntary opt-in	Voluntary opt-in
Incentive						
Participant Elasticity	1,272 kW per customer peak reduction	1,670 kW per customer peak reduction	**Own-price** elasticities average 0.07 during peak hour to 0.00 in off-peak hours	**Own-price** elasticities of 0.01 to 0.19; 30%-60% individual peak demand reductions	557 kW per customer peak reduction	
Pricing/Tariffs	Wholesale locational marginal price less retail rate, x 50%	Variety of "call" and "quote" options	Two-part RTP tariff; day ahead hourly prices	Two-part RTP tariff; day ahead and hour ahead options		
# of Customers Participating	11	282	100	1,600	106	
# Customers in Class (Potential Participants)	50,000	312	150	4,100		
Estimated Resources Delivered	14 MW	520 MW		750 MW	59 MW	425 MW
Overall Impact/ Success						
Hardware & Software Required	Interval meter	Interval meter	Interval meter	Interval meter	Interval meter	Interval meter
Meter Ownership and Cost		IOU	IOU; no extra charge to customer	IOU; no extra charge to customer	IOU	IOU
Total Program Cost/Yr						
Cost per MW		Varies	Varies	Varies	Varies	Varies
Funding Source	General rates	General rates	General rates	General rates	ISO	ISO
Cost Allocation						
Reference	Peak Load Management Alliance, "Demand Response Awards for 2001," 2002.	Goldman, "Customer Load Participation in Wholesale Markets," Presented at FERC-DOE Demand Response Conference, Feb 2002 DRAFT	Taylor, "Industrial Customer Hourly Response to Electricity Real-Time Pricing," Presented at Western Conference, CRRI, 2002. DRAFT	O'Sheasy, "Real Time Pricing Georgia Power Company," Presentation, March 26, 2001; Braithwait, "The Choice Not to Buy," Public Utilities Fortnightly, Mar 15, 2001.	van Welie, "Demand Response: The Wholesale Market Operator's Perspective," Presented at FERC-DOE Demand Response Conference, Feb 2002.	Goldman, "Customer Load Participation in Wholesale Markets," Presented at FERC-DOE Demand Response Conference, Feb 2002 DRAFT

	Midlands (U.K.) - Real-Time Pricing	Niagara Mohawk - Real Time Pricing	Portland GE - Demand Bidding	SCE - Commercial/ Industrial Time-of-Use Program	Study - Customer Elasticities	Study - Effect of Elasticity on Market Power
Program Goals	Provide full-time energy price signals	Provide full-time energy price signals	Realize peak demand reductions in response to price incentives	Determine price response to time-of-use energy and demand prices	Estimate price response to real-time prices	Determine whether demand elasticity can reduce market power in California market
Strategy-Results	Pricing. Between one-third and one-half of customers respond to prices. Between day load shifting tends to be greater than within day.	Pricing	Pricing, demand bidding.	Pricing. Customers above 200 kW exhibited significantly greater responses. Results exhibited anomalies.	Pricing, real-time pricing	Literature survey and analysis. Found there is a substantial reduction in market power when aggregate own-price demand elasticity is increased to 0.4.
Key Customer Requirements						
Status & History	Operational since 1991	Operational since 1988	Operational as of 2001	1980-1982 pilot	1997 study	1997 study using California cost data
Pilot History (if any)						
Load Shape						
Seasonality	Year round	Year round	Year round	Year round	Year round	
Parties Involved	Customer, IOU	Customer, IOU	Customer, IOU	Customer, IOU	Customer, IOU	
Marketing Responsibility	IOU	IOU	IOU	IOU	IOU	
Region	U.K.	NY	OR	CA-SCE	U.S.	
Voluntary vs. Mandatory	Voluntary opt-in	Voluntary opt-in	Voluntary opt-in	Voluntary opt-out	Voluntary	
Incentive			Customer gets 50% of savings on spot purchases	Customers compensated Peak to off-peak ratios of 1.5:1 to 2.1:1		
Participant Elasticity	**Between-day** elasticity 0.07-0.35 and **intraday** elasticity 0-0.08.	**Own-price** elasticity of 0.10 to 0.20. 36% lower critical peak demand	6,200 kW per customer peak reduction	**Substitution** elasticity of 0.03.	**Own-price elasticity** load weighted average 0.14	
Pricing/Tariffs	Half-hourly day ahead market price	Day ahead hourly prices	Bids are day ahead, pre-scheduled, and term	Peak period noon to 6 p.m.	Two-part RTP tariff; hourly prices	
# of Customers Participating	340	38	26	650		
# Customers in Class (Potential Participants)			193	500,000		
Estimated Resources Delivered		18 MW	162 MW			
Overall Impact/ Success						
Hardware & Software Required	Interval meter	Interval meter	Interval meter, pager to receive information	Time-of-use meter	Interval meter	
Meter Ownership and Cost	IOU; no extra charge to customer	IOU; no extra charge to customer	IOU	IOU; no extra charge to customer for meter		
Total Program Cost/Yr						
Cost per MW			Varies		Varies	
Funding Source			General rates			
Cost Allocation						
Reference	King, "Customer Response to Real-Time Pricing in Great Britain,"	Lafferty, "Demand Responsiveness in Electricity Markets," Presented at FERC-DOE Demand Response Conference, Feb 2002.	Goldman, "Customer Load Participation in Wholesale Markets," Presented at FERC-DOE Demand Response Conference, Feb 2002 DRAFT	Aigner, "Commercial/ Industrial Customer Response to Time-of-Use Electricity Prices: Some Experiemental Results," RAND Journal 16:3 (1985).	Gupta, "Real-Time Pricing: Ready for the Meter?" Public Utilities Fortnightly, Nov 1, 1998.	Borenstein, "An Empirical Analysis of the Potential for Market Power in California's Electricity Industry," UC Energy Institute POWER Paper PWP-044r, Dec 1998.

	Study - Estimate Commercial Energy Elasticity	U.K. - Customer Response to Real-Time Pricing	Virginia Power - Variable Pricing	Xcel Energy - Energy Controlled Service	Xcel Energy-Peak Controlled Service
Program Goals	Developed model applicable to California. Results consistent using two different models.	Determine response to half-hourly energy prices	Determine price response to industrial time-of-use rates and critical peak pricing	Pay annual discount to reduce demand during critical peaks	Pay annual discount to reduce demand during critical peaks
Strategy-Results	Pricing. Review of literature and analysis. Estimated short- and long-run elasticities using a panel of California counties.	Pricing, real-time pricing. Evaluated U.K. market	Pricing. Time-of-use with dispatchable critical peak up to 384 hours (32 days) per yr. Three day types (critical, average, low) and two periods (peak, off-pk) per day.	Emergency; customers control own load when called on by utility; up to 300 hrs/yr	Emergency; customers control own load when called on by utility
Key Customer Requirements			Customers notified of critical peaks via voice mail		
Status & History	2000 study using data from 1983-1997	Operational since 1990	Operational since 1991	Operational since late 70s	Operational since 1985
Pilot History (if any)		Pilot data for 1991-1995	1989-1990 pilot		
Load Shape					
Seasonality	Year round	Year round	Year round	Year round	Year round
Parties Involved	Customer, IOU, CEC	Customer	Customer, IOU	Customer, IOU	Customer, IOU
Marketing Responsibility		Marketers	IOU	Closed to new customers	IOU
Region	CA	U.K.	VA	Xcel-MN, MI, ND, SD, WI	Xcel-MN, MI, ND, SD, WI
Voluntary vs. Mandatory	Mandatory	Voluntary	Voluntary opt-in	Voluntary opt-in	Voluntary opt-in
Incentive			Critical peak price $0.27/kWh; off-peak price $0.02	$48-54 per kW for availability up to 300 hrs/yr; $37-45 for up to 80 hrs per yr	$48-54/kW for up to 300 hrs/yr; $37-45 for up to 80 hrs per yr
Participant Elasticity	**Own-price** non-TOU elasticity of 0.25	**Own-price** elasticities range from 0 to 0.86	40% critical peak demand reduction, 308 kW per customer	1,227 kW per customer peak reduction	163 kW per customer peak reduction
Pricing/Tariffs		Day ahead half-hourly prices	Critical peak/peak period 10 a.m. to 10 p.m.		
# of Customers Participating		520	82	110	2,575
# Customers in Class (Potential Participants)		2,000,000	880	30,000	30,000
Estimated Resources Delivered			25 MW	135 MW	421 MW
Overall Impact/ Success					
Hardware & Software Required		Interval meter	Interval meter	Interval meter	Interval meter
Meter Ownership and Cost			IOU; no extra charge to customer	IOU; no extra charge to customer	IOU; no extra charge to customer
Total Program Cost/Yr					
Cost per MW			Varies	$37,000-54,000 per yr	$37,000-54,000 per yr
Funding Source			General rates	General rates	General rates
Cost Allocation					
Reference	Garcia-Cerrutti, "Estimating Elasticities of Residential Energy Demand from Panel County Data," Resource and Energy Economics 22 (2000) .	Patrick, "Real-Time Pricing and Demand Side Participation in Restructured Electricity Markets," White Paper, Jul 2001.	Caskey, "Variable Pricing Simplified." DA/DSM International Conference Proceedings, 1995.	http://www.puc.state.mn.us/electric/rate%20design%20overview%207-30-01.pdf	http://www.puc.state.mn.us/electric/rate%20design%20overview%207-30-01.pdf

RESULTS OF USING TARIFF/PROGRAM SCREENING CRITERIA

Category	Criteria	Scoring Indicator *	PG&E Day Type TOU	SCE RTP-2	SCE RTP-PX	SCE Demand Bidding	SDG&E HPO Pilot	CEC 2-part RTP	CEC CPP	AReM Demand Bidding
Policy	Affirmative reception by all agencies	Yes, Maybe, No	Yes/m	Yes/m	Yes/m	Yes/no	Yes	yes/n	Yes/,	Yes/n
	Perceived as reasonable starting point	Yes, Maybe, No	Yes	Yes	Yes	Yes	Yes	maybe, some parties have concerns/no	Yes	Yes
	Minimize rollout time	Earlist Start Date	June '03/y	1 month from tariff approval	1 month from tariff approval	1 month from tarrff approval	In progress	June 2003 (calculation of CBLs costs time; but tariff is ready to go)	January-03	Now (CPA DRP)
	Environmental Impacts(emissions profile change)	Yes, Maybe, No	Maybe	No/m	No/m	No/m	Maybe	Yes;reduce emissions at critical times/m	Maybe	Yes/m
	Commitment to sustained Implementation	Yes, Maybe, No	Yes/m	Yes/unknown	Yes/unknown	Yes/unk	Yes	Yes/m	Yes/m	Yes via CPA/unk
	Compatible with other DR programs	Yes, Maybe, No	Yes/m	Yes/M	Yes/M	Yes/no	Yes	Yes/M	Yes/m	Generally/unk
	Compatible with other UDC interests	Yes, Maybe, No	Yes/m	Yes/m	Yes/m	Yes/m	Maybe	maybe (billing systems; dependence on AMR	Yes	Generally/m
Customer Choice	Ease of Understanding	Easy, Average, Difficult	Ave/e	Average/e	Difficult/ave	Average/diff	Easy	average; steep, short learning curve/Difficult	Easy	/difficult
	Likelihood of Substantial Customer Participation	Yes, Maybe, No	Maybe	No	No	Yes	Maybe	yes, given experience in GP and others	Yes	Yes
	Likelihood of Sustained Customer Participation	Yes, Maybe, No	Maybe	No	No	Maybe	Maybe	yes	Yes	Yes
	Customer chooses whether to respond	Yes, No	Yes	Yes	Yes	Yes	Yes	yes	Yes	Yes
	Customer controls level/method of response	Yes, No	Yes	Yes	Yes	Yes	Yes	yes	Yes	Yes

RESULTS OF USING TARIFF/PROGRAM SCREENING CRITERIA

Category	Criteria	Scoring Indicator *	PG&E Day Type TOU	SCE RTP-2	SCE RTP-PX	SCE Demand Bidding	SDG&E HPO Pilot	CEC 2-part RTP	CEC CPP	AReM Demand Bidding
DR Potential	Significant potential for participation	Estimate MW of response in 2003	200 MW/maybe	High/maybe	Low/maybe	10 -25 MW/maybe	Maybe	Yes, based on 2001 support/maybe	1 GW/maybe	200-600 MW/maybe
	Compatible with a range of industry conditions	Yes, No	Yes/no	Yes/no	Yes/no	Yes	Yes	Yes/no	Yes/no	Yes
	Focuses response when most needed	Yes, No	Yes	Yes	Yes/maybe	Yes/maybe	Yes	Yes	Yes	Yes/maybe
	Available	year round, seasonal, specific time	Year Round or Summer Only/ST	year round/seas	year round	year round	Year round	Year round	year round/ST	Year Round
	Load Impacts	peak reduction, load shift, off-peak load building, general load building	peak reduction and load shifting	peak reduction, load shift, off-peak load building	peak reduction, load shift, off-peak load building	peak reduction	All	all	peak reduction, load shift, off-peak load building	Peak Reduction
	Potential for system benefits from response	1:1, >1:1, other	>1:1	tbd	tbd	>1	Yes	>1:1	??	>1:1
Equity	Probability of Net system benefits	Yes, No	Yes	yes	yes	Yes	Yes	yes	Yes	Yes
	Cost Recovery	Describe who pays?	reduced surcharge rev recoverable through bal acct amort	Rev Neutral w/respect to existing class billing determinants	Rev Neutral w/respect to existing class billing determinants	Memo account, adj cap	Class	Can be Rev Neutral through part 1 desigm and CBL	participants	CPA --DR Providers
	Benefit allocation	Describe who benefits?	All	Customer, system	Customer, system	Customer, system	Participants/ All	customer; system	participants, system	Participants -- and all
	Nature of Proposed Revenue Neutrality	System, Class, Customer	Class	Class	Class	system	Class	System, class	System, Class	Automatic
	Discriminate by size or end-use	Yes, No	No	Yes, >200kw/no	Yes, >200kw/no	Yes, >100kw	No	Yes, >200 kW/no	No	Yes/unkown
	Gaming opportunities	Yes, Maybe, No	No	No	No	No, 10 day CBL/yes	No	No/yes	No	Little/yes

RESULTS OF USING TARIFF/PROGRAM SCREENING CRITERIA

Category	Criteria	Scoring Indicator *	PG&E Day Type TOU	SCE RTP-2	SCE RTP-PX	SCE Demand Bidding	SDG&E HPO Pilot	CEC 2-part RTP	CEC CPP	AReM Demand Bidding
Costs	Infrastructure costs	High, medium, Low	Low	Low	Low/medium	Low/m	Low	low/high	low	low (Call Option)/m
	O&M and financial carrying costs	High, medium, Low	Low	Low	Low/m	Low/m	Medium	low/medium	low	low (Call Option)/m
	Marketing and education costs	High, medium, Low	Low	medium	medium	Low	Medium	high	medium	low
	Scalability of UDC infrastructure	Yes, No	Yes	Yes	Yes	Yes	Yes	yes/low	Yes	Yes
	UDC Cost recovery	Explicit, Deferred	Deferred	Explicit and guaranteed thru surcharge or other , incl. admin, incentive, insfrastructure, revenue shortfall, record in memo accounts	Explicit and guaranteed thru surcharge or other , incl. admin, incentive, insfrastructure, revenue shortfall, record in memo account	Explicit and guaranteed thru surcharge or other , incl. admin, incentive, insfrastructure , revenue shortfall, record in memo account	Unknown*	Explicit, method unspecified	Explicit, method unspecified	Yes, as commodity purchase
	Customer costs	High, Medium, Low	Low	Low	Low to Medium	Low/m	Low	low/medium	(scaleable)/low	low-medium/m
Implementation Issues	Penalties/incentives	Required, Not Required	Not Required	Not required	Not required	Not required	None	not required	not required	ISO imbalance energy costs
	Resource planning M&E	Easy, Hard	Moderate	Easy, need operating experience to gauge response	Easy, need operating experience to gauge response	Easy, need operating experience to gauge response	Unknown	Easy, need operating experience to gauge response	?	easy
	Compliance M&E	Required, Not Required	Not Required	Required for revenue neutrality	Required for revenue neutrality/NR	Required, billing verification/NR	Not Required	not required	not required	Built in/NR
	Administrative Difficulty	High, Medium, Low	Medium/low	High/low	High/medium	Low, increases with usage due to manual billing/high	Low	medium	Low	Medium/high
	Development/Implementation Risk	High, Medium, Low	Low	Medium/low	Medium	Low/medium	Low	low/high	Low	Low/high

Example Calendar for PG&E's Proposed Summer RTP/CPP Price Signals

June, 2001

Sun	Mon	Tue	Wed	Thu	Fri	Sat
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30

July, 2001

Sun	Mon	Tue	Wed	Thu	Fri	Sat
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30	31				

August, 2001

Sun	Mon	Tue	Wed	Thu	Fri	Sat
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30	31	

September, 2001

Sun	Mon	Tue	Wed	Thu	Fri	Sat
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30						

Legend:

- 14 High-Price Weekdays (procurement surcharges are much higher than standard tariff, to 50-75 cents/kWh in highest-priced hours)
- 28 Mid-Price Weekdays (procurement surcharges are set at same level as standard tariff on these mid-range operating days)
- 42 Low-Price Weekdays and All Weekends/Holidays (surcharges are set at 50% of the standard tariff on these lowest-priced days)

1. CURRENT RATES

	Days	Numbers of Hours On-Pk	Numbers of Hours Pt-Pk	Numbers of Hours Off-Pk	Nominal Load Ratios On-Pk	Nominal Load Ratios Pt-Pk	Nominal Load Ratios Off-Pk	TOU Prices on E-EPS On-Pk	TOU Prices on E-EPS Pt-Pk	TOU Prices on E-EPS Off-Pk
Weekdays:	84	6	7	11	1.026	1.000	0.892	9.13	4.13	3.13
Wkend/Hol:	38	N/A	N/A	24	N/A	N/A	0.804	N/A	N/A	3.13

Total Usage (Millions of kWh)

On-Pk	Pt-Pk	Off-Pk
1,062	1,208	1,694
Total:	**5,471**	1,506

Calculations shown here are for illustrative class-average E-20 rates. Example bill projections on next two pages are based on the following voltage-specific cost multipliers:

[nominal load ratios estimated using summer 2001 load data]

2,108 2,055 1,834 [Average MW TOU Loads]

Revenue (Millions of Dollars)

On-Pk	Pt-Pk	Off-Pk
$97.0	$49.9	$53.0
Total:	**$247.1**	$47.1

E-20 T	388%	On-Pk	55%	Low-price and weekends
E-20 P	382%	"	50%	"
E-20 S	360%	"	50%	"

2. RTP/CPP RATES

	Days	Nominal Load Ratios On-Pk	Nominal Load Ratios Pt-Pk	Nominal Load Ratios Off-Pk	Specified Price Ratios On-Pk	Specified Price Ratios Pt-Pk	Specified Price Ratios Off-Pk	TOU Prices on E-RTP On-Pk	TOU Prices on E-RTP Pt-Pk	TOU Prices on E-RTP Off-Pk
High Price:	14	1.051	1.019	0.894	**384%**	250%	250%	35.07	10.33	7.83
Mid-Price:	28	1.031	1.005	0.902	100%	100%	100%	9.13	4.13	3.13
Low Price:	42	1.014	0.990	0.885	50%	50%	**50%**	4.57	2.07	1.57
Wkend/Hol:	38	N/A	N/A	0.804	N/A	N/A	**50%**	N/A	N/A	1.57

[nominal load ratios by day-type reflect class-average temperature-sensitive demand]

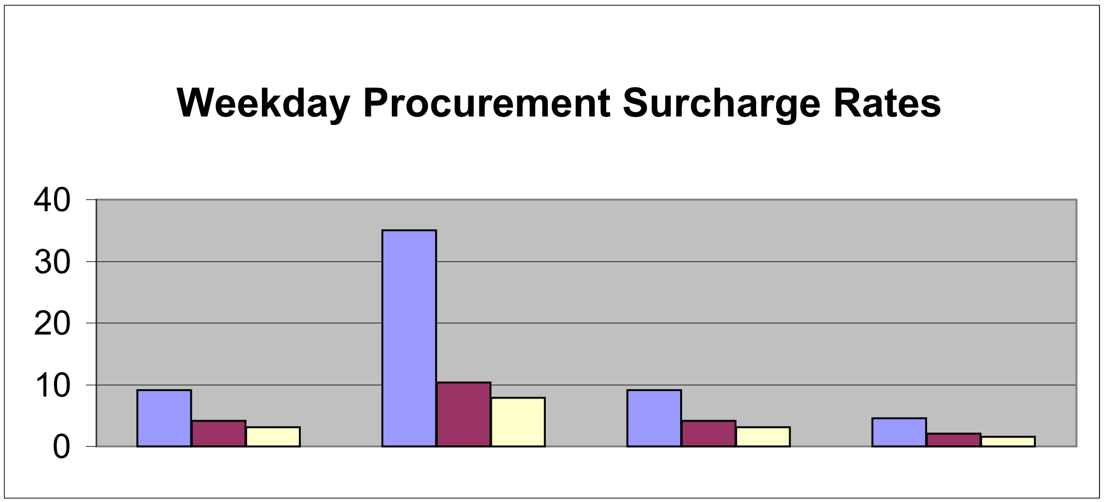
Total Usage (Millions of kWh)

	On-Pk	Pt-Pk	Off-Pk
High:	181	205	283
Mid:	356	405	571
Low:	525	598	841
	Total:	**5,471**	1,506

Revenue (Millions of Dollars)

	On-Pk	Pt-Pk	Off-Pk
High:	$63.6	$21.2	$22.1
Mid:	$32.5	$16.7	$17.9
Low:	$24.0	$12.4	$13.2
	Total:	**$247.1**	$23.6

PRICES SHOWN ARE CENTS/KWH



CURRENT RATES

D. 01-05-064 Rates Every Weekday

PG&E's CPP/RTP PROPOSAL FOR SUMMER 2003

14 High-Price Weekdays

28 Mid-Price Weekdays

42 Low-Price Weekdays

Numbers of Hours

	On-Pk	Pt-Pk	Off-Pk
High:	84	98	154
Mid:	168	196	308
Low:	252	294	462
Weekend Off-Peak:			912

Average Loads by Day Type

	On-Pk	Pt-Pk	Off-Pk
High:	2,159	2,094	1,836
Mid:	2,118	2,066	1,854
Low:	2,083	2,035	1,820
Weekend Off-Peak:			1,651

REPRESENTATIVE CUSTOMER DEMOGRAPHICS				LOAD CHARACTERISTICS			STD vs. CPP			Amount	High Day CPP Bills			Break-Even
SCHED	CUST	CUSTOMER TYPE	LOCATION	Max kW	AvgMWH	kWh/kW	Std.	CPP		Different	per day	14 days		Load Chng
E20T	1	SEASONAL MAN.	CEN. VALLEY	6,078	4,023	662	$742	$712	-	$30.1	$19.6	$275k	+	11%
E20T	2	ASSEMBLY IND.	CEN. VALLEY	7,706	5,273	684	$971	$976	+	$5.0	$28.7	$402k	-	1%
E20T	3	ASSEMBLY IND.	BAY AREA	32,696	18,182	556	$3,483	$3,570	+	$86.8	$104.3	$1,460k	-	6%
E20T	4	OFFICE BUILDING	BAY AREA	4,234	2,383	563	$459	$480	+	$20.9	$14.8	$208k	-	10%
E20T	5	SEASONAL MAN.	CEN. VALLEY	7,390	3,632	491	$611	$618	+	$7.2	$17.9	$251k	-	3%
E20T	6	RESOURCE EXT.	CEN. VALLEY	25,566	18,489	723	$3,367	$3,330	-	$37.0	$94.9	$1,328k	+	3%
E20T	7	SEASONAL MAN.	CEN. VALLEY	5,881	3,669	624	$688	$639	-	$49.5	$16.4	$230k	+	21%
E20T	8	ASSEMBLY IND.	BAY AREA	6,005	3,981	663	$737	$742	+	$4.5	$21.7	$304k	-	1%
E20T	9	SEASONAL MAN.	CEN. VALLEY	5,217	3,178	609	$599	$591	-	$8.0	$16.9	$237k	+	3%
E20T	10	FOREST PROD.	NORTH COAST	4,170	2,356	565	$420	$410	-	$10.8	$11.0	$154k	+	7%
		E20T	**GROUP AVG:**	10,077	6,281	623	$1,166	$1,166		$0.0	$33.5	$469k		0%
E20P	1	HOSPITAL	BAY AREA	1,935	1,130	584	$213	$216	+	$2.8	$6.9	$96k	-	3%
E20P	2	DIST. CENTER	BAY AREA	2,593	1,715	662	$314	$312	-	$2.2	$9.7	$136k	+	2%
E20P	3	SEASONAL MAN.	CEN. VALLEY	2,704	1,394	516	$268	$274	+	$5.4	$8.6	$120k	-	4%
E20P	4	HOSPITAL	BAY AREA	1,916	1,089	568	$207	$216	+	$8.3	$7.1	$100k	-	8%
E20P	5	SEASONAL MAN.	BAY AREA	1,609	876	544	$167	$171	+	$3.6	$5.3	$74k	-	5%
E20P	6	ASSEMBLY IND.	BAY AREA	1,650	1,032	625	$185	$179	-	$5.7	$5.4	$75k	+	8%
E20P	7	OFFICE BUILDING	BAY AREA	2,091	1,344	643	$247	$247	-	$0.3	$7.8	$109k	+	0%
E20P	8	ASSEMBLY IND.	CEN. VALLEY	2,570	1,764	686	$320	$306	-	$13.5	$9.1	$128k	+	11%
E20P	9	OFFICE BUILDING	CEN. VALLEY	2,650	1,586	599	$298	$303	+	$5.0	$9.6	$135k	-	4%
E20P	10	HOSPITAL	CEN. VALLEY	2,281	1,441	632	$268	$264	-	$3.4	$8.1	$113k	+	3%
		E20P	**GROUP AVG:**	2,200	1,337	608	$249	$249		$0.0	$7.8	$109k		0%
E20S	1	OFFICE BUILDING	BAY AREA	1,630	612	376	$130	$139	+	$9.5	$4.7	$66k	-	14%
E20S	2	ASSEMBLY IND.	BAY AREA	998	559	560	$105	$104	-	$1.1	$3.2	$45k	+	2%
E20S	3	OFFICE BUILDING	BAY AREA	1,113	426	383	$89	$95	+	$6.0	$3.2	$45k	-	13%
E20S	4	SHOPPING CTR.	BAY AREA	1,246	574	460	$112	$112	-	$0.2	$3.5	$49k	+	0%
E20S	5	HOSPITAL	BAY AREA	1,779	938	527	$180	$178	-	$1.3	$5.5	$78k	+	2%
E20S	6	OFFICE BUILDING	BAY AREA	1,788	776	434	$157	$166	+	$8.7	$5.5	$77k	-	11%
E20S	7	ASSEMBLY IND.	CEN. VALLEY	2,439	1,422	583	$266	$265	-	$0.4	$7.9	$111k	+	0%
E20S	8	ASSEMBLY IND.	BAY AREA	869	608	700	$109	$105	-	$4.4	$3.0	$43k	+	10%
E20S	9	HOSPITAL	BAY AREA	1,195	723	605	$134	$132	-	$1.8	$4.1	$57k	+	3%
E20S	10	ASSEMBLY IND.	CEN. VALLEY	2,401	1,697	707	$302	$287	-	$15.0	$8.3	$117k	+	13%
		E20S	**GROUP AVG:**	1,546	834	539	$158	$158		$0.0	$4.9	$69k		0%

Shaded boxes identify customers who would need to significantly **lower** their load on high-price CPP days

Open boxes identify customers who could **increase** their load on high-price CPP days and still break even

REPRESENTATIVE CUSTOMER DEMOGRAPHICS					Break-Even	WEEKDAY KWH			On-Pk	Wknd	EXPLANATORY NOTES -- FOR CUSTOMERS WITH LARGE +/- BREAK-EVEN LOAD CHNG
SCHED	CUST	CUSTOMER TYPE	LOCATION		Load Chng	High	Mid	Low	Usage	Usage	
E20T	1	SEASONAL MAN.	CEN. VALLEY	+	11%	0.91	0.88	1.11	1.01	0.85	This customer's seasonal peak is in September
E20T	2	ASSEMBLY IND.	CEN. VALLEY	-	1%	1.01	0.97	1.01	1.01	0.87	
E20T	3	ASSEMBLY IND.	BAY AREA	-	6%	0.92	1.00	1.02	1.07	0.53	Customer's weekend usage level is quite low
E20T	4	OFFICE BUILDING	BAY AREA	-	10%	1.06	1.01	0.98	1.22	0.85	Office building attached to manufacturing plant
E20T	5	SEASONAL MAN.	CEN. VALLEY	-	3%	1.02	1.03	0.97	0.55	0.53	
E20T	6	RESOURCE EXT.	CEN. VALLEY	+	3%	1.00	1.00	1.00	1.00	1.00	
E20T	7	SEASONAL MAN.	CEN. VALLEY	+	21%	0.79	0.85	1.17	1.08	0.80	This customer's seasonal peak is in September
E20T	8	ASSEMBLY IND.	BAY AREA	-	1%	1.02	0.99	1.00	1.06	0.92	
E20T	9	SEASONAL MAN.	CEN. VALLEY	+	3%	0.92	0.91	1.09	1.07	0.71	
E20T	10	FOREST PROD.	NORTH COAST	+	7%	0.89	1.03	1.02	0.83	0.73	Customer operated at 25% load week of July 2-5
		E20T	**GROUP AVG:**		0%	0.99	1.02	1.06	1.05	0.80	
E20P	1	HOSPITAL	BAY AREA	-	3%	1.08	1.02	0.96	1.18	0.90	
E20P	2	DIST. CENTER	BAY AREA	+	2%	1.05	1.00	0.98	1.04	0.90	
E20P	3	SEASONAL MAN.	CEN. VALLEY	-	4%	0.98	1.00	1.01	1.10	0.48	
E20P	4	HOSPITAL	BAY AREA	-	8%	1.13	1.02	0.94	1.23	0.92	Customer with high peak-day and on-peak usage
E20P	5	SEASONAL MAN.	BAY AREA	-	5%	0.96	1.05	0.98	1.09	0.52	
E20P	6	ASSEMBLY IND.	BAY AREA	+	8%	1.03	0.99	1.00	0.94	0.90	Customer has "best in class" daily load shape
E20P	7	OFFICE BUILDING	BAY AREA	+	0%	1.09	1.00	0.97	1.08	0.97	
E20P	8	ASSEMBLY IND.	CEN. VALLEY	+	11%	1.01	0.98	1.01	1.03	1.02	Customer has "best in class" weekend usage
E20P	9	OFFICE BUILDING	CEN. VALLEY	-	4%	1.09	1.03	0.95	1.15	0.85	
E20P	10	HOSPITAL	CEN. VALLEY	+	3%	1.05	1.02	0.97	1.12	0.94	
		E20P	**GROUP AVG:**		0%	1.05	1.01	0.98	1.09	0.85	
E20S	1	OFFICE BUILDING	BAY AREA	-	14%	1.07	0.98	0.99	1.56	0.46	Office building load with low weekend usage
E20S	2	ASSEMBLY IND.	BAY AREA	+	2%	1.05	0.99	0.99	1.18	0.87	
E20S	3	OFFICE BUILDING	BAY AREA	-	13%	1.06	0.98	0.99	1.48	0.46	Office building load with low weekend usage
E20S	4	SHOPPING CTR.	BAY AREA	+	0%	1.05	1.01	0.97	1.44	0.97	
E20S	5	HOSPITAL	BAY AREA	+	2%	1.05	0.98	1.00	1.29	0.86	
E20S	6	OFFICE BUILDING	BAY AREA	-	11%	1.08	0.99	0.98	1.42	0.62	Office building load with low weekend usage
E20S	7	ASSEMBLY IND.	CEN. VALLEY	+	0%	0.95	1.06	0.98	1.06	0.55	
E20S	8	ASSEMBLY IND.	BAY AREA	+	10%	1.01	1.05	0.96	1.02	0.95	Small manufacturer with high weekend usage
E20S	9	HOSPITAL	BAY AREA	+	3%	1.06	1.00	0.98	1.16	0.94	
E20S	10	ASSEMBLY IND.	CEN. VALLEY	+	13%	1.02	1.01	0.98	1.00	1.00	Small manufacturer with high weekend usage
		E20S	**GROUP AVG:**		0%	1.03	1.01	0.98	1.22	0.78	